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SCIENCE APPLICATIONS, INC.

SOLAR THERMAL PLANT IMPACT ANALYSIS AND REQUIREMENTS DEFINITION STUDY

FINAL REPORT

CONTRACT NO. 955238

Submitted to
CALIFORNIA INSTITUTE OF TECHNOLOGY
JET PROPULSION LABORATORY
4800 Oak Grove Drive
Pasadena, California 91103

Submitted by
SCIENCE APPLICATIONS, INC.
1710 Goodridge Drive
McLean, Virginia 22102

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FOREWORD

This report summarizes work performed under the Solar Thermal Electric Power Systems Impact Analysis and Requirements Definition Study. The study has been performed by Science Applications, Inc. (SAI) and its subcontractor Black and Veatch, Inc. (B&V) under Contract Number 955238 to the Jet Propulsion Laboratory (JPL), Pasadena, California. The objectives of the study are to select case studies from potential solar electric system types, site locations, and applications and to evaluate these cases with respect to system performance, system impacts and economic analysis, conceptual design and requirements definition.

Technical direction for this work was provided by Mr. S. Bluhm, Mr. T. Quo, and Dr. K. Terasawa of JPL. The Project Manager for SAI was Dr. Y. Gupta. Key SAI technical contributers included Dr. S. Young, Mr. R. Edwards, and Mr. D. Edelman. Contributers for B&V included Dr. S. Levy as B&V Project Manager, Mr. L. Stoddard as B&V Project Engineer, and Mr. D. Gray.

ACRONYMS

The following acronyms are used in this document:

B&V	Black and Veatch Consulting Engineers, Inc.
EPRI	Electric Power Research Institute
FCR	fixed charge rate
HD	hybrid dispatch
ID	dispatch of hybrid fuel based on incremental heat rate
IOU	investor owned utility
JPL	Jet Propulsion Laboratory
LOLP	loss of load probability
MUNI	municipal utility
NH	no hybrid
NS	no storage
O&M	operation and maintenance
PFDR	point focus distributed receiver solar thermal electric power system utilizing dish collectors
QAG	solar thermal electric performance model
REC	rural electric cooperative utility
S	storage
SAI	Science Applications, Inc.
SCE	Southern California Edison
SF	sun-following dispatch of storage
SYSGEN	conventional utility production costing model
TOD	time of day dispatch of storage or hybrid fuel

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SUMMARY

SECTION 1

SUMMARY

1 STUDY OVERVIEW

Generation of electric power by solar thermal electric small power systems has been identified by the U.S. Department of Energy as a candidate technology for reducing national fossil fuel dependency. As part of a broad program in energy research, the Jet Propulsion Laboratory (JPL) has been actively exploring the technology and economics of solar thermal electric systems (STES) for electric power production. This study is being performed for JPL by Science Applications, Inc. (SAI) and its subcontractor Black and Veatch (B&V) to evaluate the impacts of and requirements for solar thermal electric power systems. Specific objectives include:

- development of a solar thermal electric data base
- development of an impacts analysis methodology
- impacts analysis of solar thermal electric systems for selected applications, including evaluation of:
  - fuel savings
  - capacity displacement
  - reliability
  - economic impacts
  - solar penetration
  - solar system economic value
- requirements definition for solar thermal electric systems, including:
  - design configurations
  - functional requirements
  - cost projections
  - operational, installation, and safety requirements.

An overview of the study is provided in Figure 1-1.

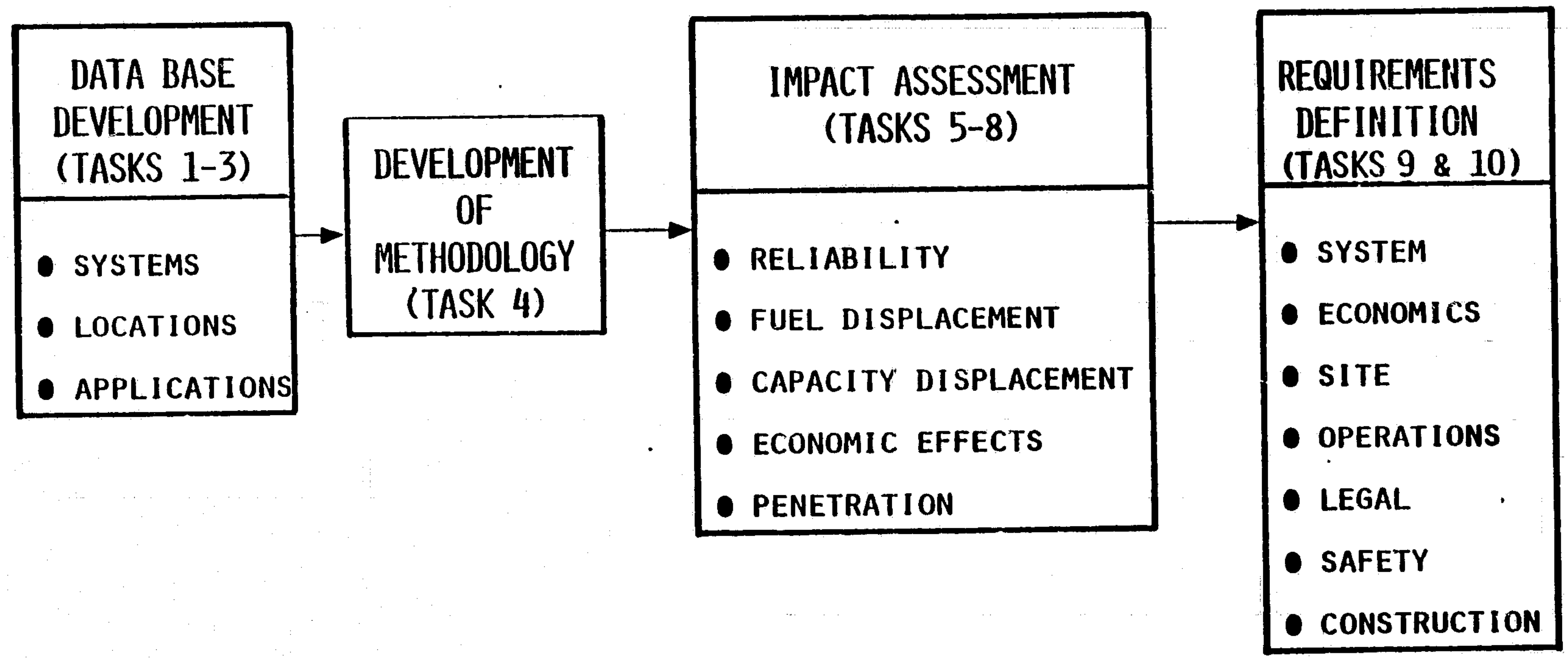

FIGURE 1-1. Study Overview

2 SOLAR THERMAL ELECTRIC IMPACTS ANALYSIS

The value of solar plants integrated in a power system consists of both fuel savings and capacity savings in meeting a specified reliability level. The economics of solar generation depends on a number of variables -- the mix and cost of conventional generation; the match between solar generation profiles and the electric system load shape; the amount of solar generation; the design configuration (storage, hybrid fuel, etc.) of the solar plant; and the solar system dispatch strategy. All of the factors must be analyzed in an integrated methodology to properly evaluate solar system impacts.

A detailed description of the impacts of solar thermal electric systems is provided in Part 2 of this report. As an example, Figure 1-2 illustrates the breakeven costs of a point focus, distributed receiver, distributed generation solar thermal electric systems for a large investor-owned utility. The solar system is assumed to be located in Albuquerque with conventional fuel costs and economic assumptions as described later in Section 3. Key results of the analysis are as follows:

- Solar system value is primarily as a fuel saver. Solar system value is increased greatly if the solar output is matched to load peaks.
- Solar generation does not displace any single resource type -- a mix of oil, coal, and gas generation is displaced.
- Solar system value decreases with increasing penetration level, and can drop significantly above 20% penetration for utilities having nuclear or coal base generation.
- Solar capacity displacement is a mix of peaking and intermediate capacity, depending on the load shape. If solar output is coincident with peak demand, peaking capacity is displaced in the range of 20 to 40% of solar capacity (at low penetration). If solar electric output is shifted off peak demand (which is often the case for heating/cooling - dependent loads), intermediate loads are displaced and solar penetration may displace some coal capacity, with no displacement or even addition of peaking capacity to supply the remaining peak loads. Some capacity credit can be obtained in capital cost savings (peaking capacity is cheaper than coal capacity) but little net MW capacity displacement occurs.

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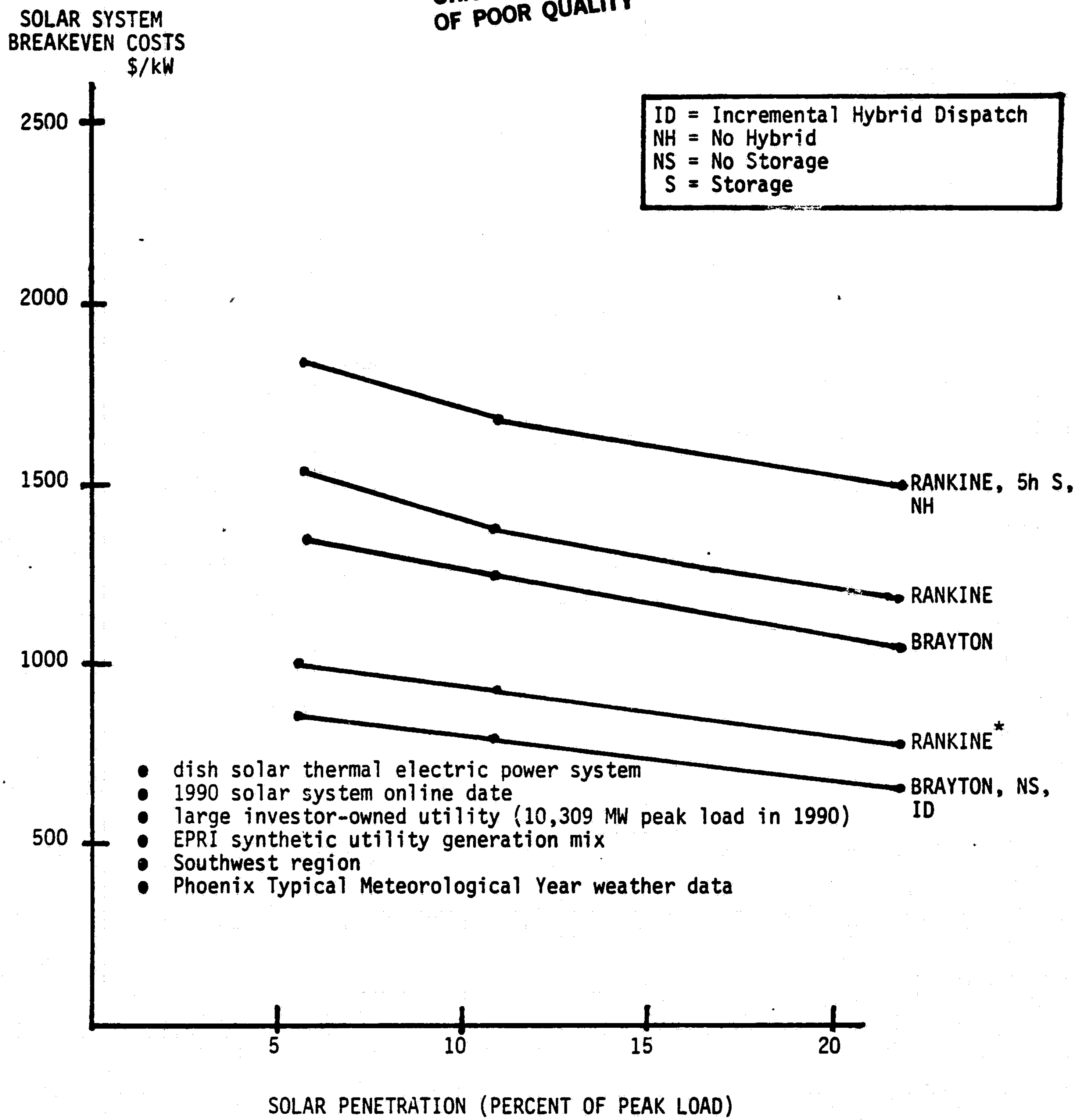

* Fort Worth Site Sensitivity.

FIGURE 1-2. Solar System Breakeven Costs — Investor-Owned Utility/Financing

- The value of solar systems can be substantially increased by using storage. However, the cost of storage and its associated additional collector area is expected to exceed the additional value.

- Hybrid fossil/solar system configurations for new generation do not appear to be cost effective for utilities having fossil generators with higher conversion efficiencies than the solar system.

- Utility economic parameters, generation mix, and fuel costs have a dominant impact on solar system value.

- Ownership alternatives and solar system financial assumptions have a dominant impact on the breakeven price and cost effectiveness of solar plants.

3 SOLAR THERMAL ELECTRIC PLANT REQUIREMENTS DEFINITION

Conceptual design, first order cost estimates, and requirements definition are presented in Part 2 of this report for ten different system concepts. The system concepts and associated cost estimates are summarized in Figure 1-3. The system concepts selected include a range of design alternatives:

- central versus dispersed generation
- Rankine, Brayton, and Stirling thermodynamic cycles
- different energy transport modes (electric, oil, sodium, steam)
- storage, no storage, and hybrid fossil configurations.

The designs are based on a 1990 time frame assuming adequate technology and market maturity to permit mass production techniques.

An inspection of system costs on a per kWe basis shows a large range of costs, from $1,727/kWe to $7,408/kWe. Cost differences can be attributed to several key factors. First, those systems having energy storage (Cases 1, 3, 4, 5, 6, 7 and 10) have significantly higher capital costs than would similar systems without storage. These higher costs are due in part to the added cost of the storage system, but even more to the incrased collector field size necessary to accommodate the storage. Because these systems with storage produce greater annual energy, the higher capital costs do not imply equally higher costs of energy.

Case	Location/Application	System Configuration	Conversion Cycle	Net Rated System Capacity	Concentrator Design	Energy Transport	Storage/ Hybrid	Sensitivity Studies	System Capital Cost*	System Cost* $/kWe	Comments
1	Fort Worth, Texas, Municipal Utility	Central	Six 1 MWe Organic Rankine Turbines, 427 C (800 F)	5.6 MWe	G.E.	Sodium 454 C (850 F)	5-Hour Thermal	Subsystem Size/Cost	40,209,000	7,180	High system cost related to high cost of piping, particularly for alloy steel.
2	Phoenix, Arizona, Isolated Government Installation	Dispersed	Open Cycle Brayton 871 C (1,600 F)	10 MWe	G.E.	Electric	Hybrid	None	25,481,000	2,548	Moderate power conversion costs and use of hybrid instead of storage lead to "moderate" system costs.
3	Phoenix, Arizona, Investor-Owned Utility	Central	Nine 1 MWe Organic Rankine Turbines 371 C (700 F)	8.4 MWe	G.E.	Silicone Oil (Syltherm 800) 399 C (750 F)	5-Hour Thermal	Use Single 9 MWe Turbine	62,230,000	7,408	Oil specified as lower temperature heat transfer medium for comparison with Case 1. Higher storage cost and lower conversion efficiency offset replacing of alloy steel of Case 1 with carbon steel pipe.
4	Phoenix, Arizona, Investor-Owned Utility	Central	Single Steam Rankine Turbine 510 C (950 F)	9 MWe	G.E.	Steam 510 C (950 F)	5-Hour Thermal	Turbine Inlet Temperature	56,784,000	6,399	High system cost related to high cost of piping.
5	Fort Worth, Texas, Industry connected to Municipal Utility	Central, with Process Heat	Single Non-condensing Steam Rankine Turbine 510 C (950 F)	6 MWe	G. E.	Steam 510 C (950 F)	5-Hour Thermal	Use 3 MWe Turbine	53,855,000	8,976	Cost per kWe misleading because process steam is utilized.
6	Phoenix, Arizona, Industry	Central	Single Steam Rankine Turbine 510 C (950 F)	9 MWe	G. E.	Steam 510 C (950 F)	5-Hour Thermal	None	56,146,000	6,238	Case 6 is redesign of Case 4 with a new piping system design. Small cost savings realized.
7	Barstow, California, Large Investor-Owned Utility	Dispersed	Stirling Engine 810 C (1,490 F)	10 MWe	G.E.	Electric	3-Hour Battery	Subsystem Size/Cost	36,208,000	3,621	Storage significantly impacts cost/kW when compared with Case 8.
8	Fort Worth, Texas, Municipal Utility	Dispersed	Stirling Engine 810 C (1,490 F)	10 MWe	Acurex	Electric	None	Concentrator Size	17,267,000	1,727	Low assumed costs for mature Stirling engine technology and market and lack of storage contribute to lowest system cost of 10 cases.
9	Phoenix, Arizona, Isolated Government Installation	Dispersed	Closed Cycle Brayton 871 C (1,600 F)	10 MWe	Acurex	Electric	None	Concentrator Size	27,072,000	2,707	Moderate power conversion costs and lack of storage contribute to "moderate" system costs.
10	Barstow, California, Large Investor-Owned Utility	Dispersed	Organic Rankine 427 C (800 F)	10 MWe	Acurex	Molten Salt 454 C (850 F) Electric	3-Hour Thermal, at Each Collector	5-Hour Storage	61,437,000	6,144	High power conversion unit and storage costs contribute to high system cost

*1980 Dollars.

FIGURE 1-3 SYSTEM CONCEPTS AND COSTS SUMMARY

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A second key factor in cost differences is the high cost of piping systems for those cases utilizing central generation (Cases 1, 3, 4, 5 and 6). For this study, piping systems were designed and costed on the basis of currently standard practices for power plants. It is possible that significant reductions in piping system costs could be achieved by automated factory assembly, semi-automated field installation of components, and the field application of flexible pipes to reduce installation costs and replace expansion loops.

A third factor in system cost differences is the high efficiency of Stirling engine cycles as opposed to other cycles (41 per cent, versus 35 per cent for the Case 4 steam Rankine cycle and down to 26 per cent for the Case 10 organic Rankine cycle). The high Stirling cycle efficiency results in a significant reduction in the required number of collectors, the most expensive elements of the system.

A fourth factor in the system cost differences is the assumed cost of power conversion equipment. The low cost systems utilizing Stirling engines (and, in particular, Case 8 for which there is no storage) reflects a projected installed cost of about $200/kWe for Stirling engines (plus alternators and heat rejection), based on DOE cost goals for a mature technology and market. This cost per kWe is about one half of that projected for Brayton cycle units, and one third of that projected for the central generation Rankine cycle units. The ability to achieve the low system cost of Case 8 is dependent on achieving the mature technology and market for the Stirling engines.

In conclusion, from a capital cost perspective, the preferred configuration is a dispersed generation system using a Stirling cycle power conversion. This selection is predicated on devleopment of the Stirling engine to a mature technology, and upon reduction of costs through mass production. A second key conclusion is that central generation systems do not appear to be attractive alternatives unless piping costs are reduced significantly.

4 SOLAR THERMAL ELECTRIC COST REQUIREMENTS

Solar system breakeven costs vary from less than \$1000/kWe to over \$3000/kWe depending on the various factors mentioned in Section 1.4. Solar system cost estimtes shown in Figure 1-3 range from \$1700/kWe to over \$7400/kWe depending primarily on the type of system configuration. Based on an evaluation of breakeven system costs it appears that solar electric power systems using dispersed generation will be cost competitive by 1990 for the following favorable types of applications:

- Municipal or electric cooperative utilities, which have generally lower financing costs and do not have tax deductible fuel costs, thereby encouraging the use of capital intensive low operating cost technlogies such as solar.
- Stand-alone utilities which have high fuel costs, particularly for governmental or institutional applications which do not receive tax subsidies for fuel consumption.

Economics for solar systems connected to a large investor-owned utility are less promising, but still remain favorable for the preferred dispersed generation concepts. Figure 1-4 indicates that penetration levels of 10 to 15% are viable for solar system costs of 1500 to 2000 \$/kWe.

As shown later in Part 1 of the report, solar system benefits are very sensitive to economic assumptions. These assumptions must be considered in evaluating the results of the study. Fuel prices in particular have increased much more dramatically than assumed at the time of this study, thereby increasing the value of solar systems. Financing costs have also increased (even after adjustment for inflation), but may be significantly offset by accelerated depreciation regulations which have recently been legislated. Thus, the trends indicated by this study remain valid but must be adjusted before application to a particular utility or case study.

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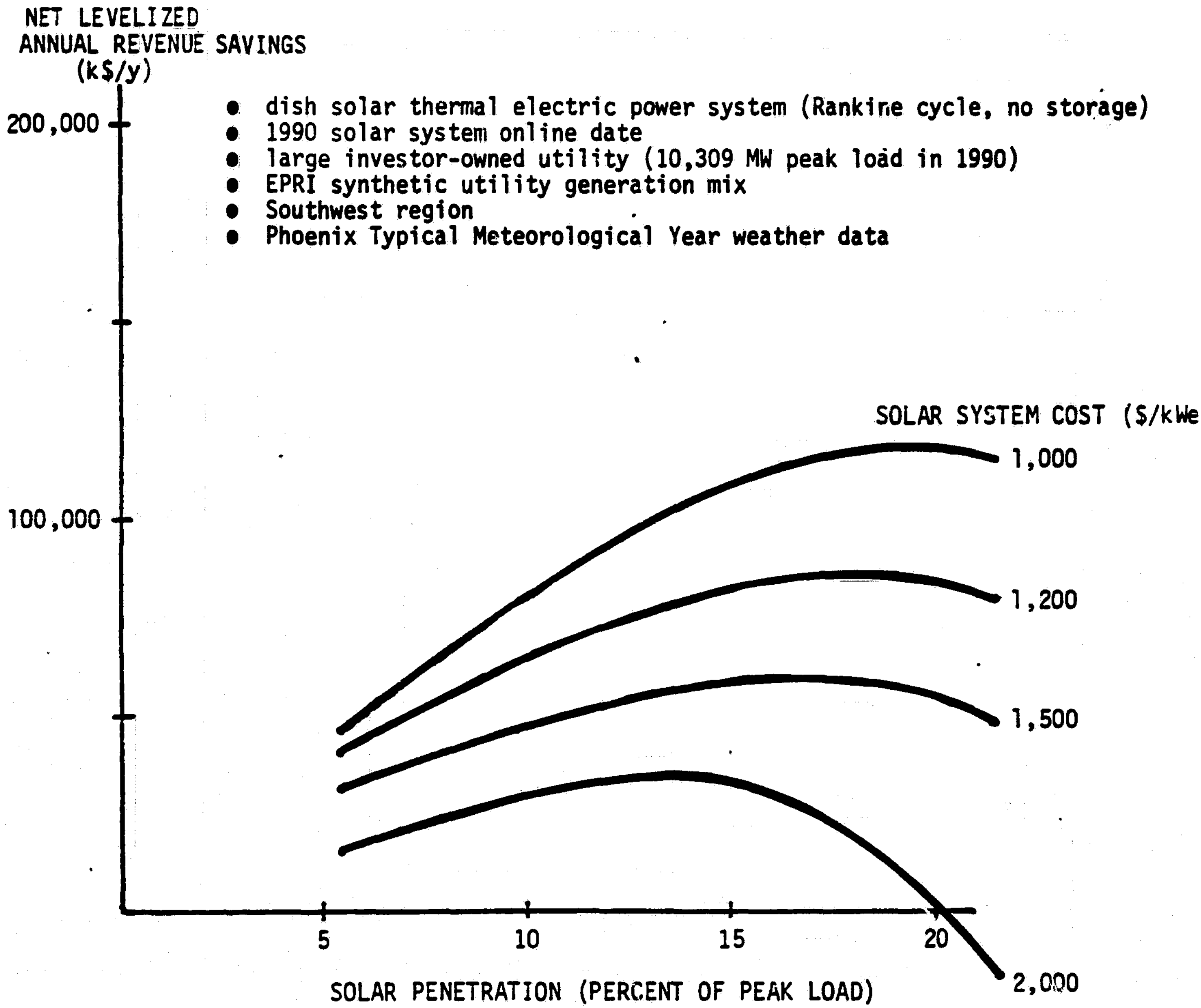

FIGURE 1-4 Solar System Net Worth—Investor-Owned Utility, Rankine, No Storage, No Hybrid System

PART I

IMPACTS ANALYSIS

SECTION 2

IMPACTS ANALYSIS APPROACH

SECTION 2

IMPACTS ANALYSIS APPROACH

Solar thermal electric plants affect the performance, economics, and reliability of the overall electric energy supply system. Interactions between solar plant operation, backup requirements, and conventional generation have a major impact on solar system design and economics. Thus, it is important to properly evaluate solar electric plants in the context of total system reliability, cost, and performance.

SAI has developed a methodology which evaluates the performance and economics of solar electric technologies within the overall conventional generation system. The methodology consists of five parts:

- hourly simulation of solar electric system performance
- hourly subtraction of solar system output from projected utility loads
- capacity expansion and mix adjustment for the conventional utility system (both with and without solar generation)
- production costing for the resulting conventional utility mix (with and without solar generation)
- economic analysis of the solar plant value to the utility and evaluation of solar system breakeven costs for different ownership alternatives.

In the economic analysis, the value of the solar system to the utility is first determined as the total present value cost difference between solar and no-solar cases, with the resulting savings being distributed to the solar plant owners.

The methodology has been documented previously in the Task 4 Report*. For the reader's convenience, an overview of the methodology is presented in Appendix A.

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*Solar Thermal Plant Impact Analysis and Requirements Definition Study, Summary Report for Task 4 -- Methodology Development, JPL Contract #955238, 15 February 1908.

SECTION 3

IDENTIFICATION OF IMPACTS ANALYSIS CASE STUDIES

SECTION 3

IDENTIFICATION OF IMPACTS ANALYSIS CASE STUDIES

This section describes the case studies and detailed assumptions selected for preliminary analysis of the impacts and economics of solar thermal electric plants. The formulation of the SAI impacts analysis methodology is such that it is possible to choose a location, a system type, and a utility type and mix, and to range across several types of ownership alternatives for the impact analysis with respect to the chosen utility. Thus, the focus shifts to the choice of utility type and its relationship with the system type and location.

3.1 CASE STUDY RATIONALE

For the impacts analysis case studies it was decided to pick one representative from each of the three classes of utilities -- large utilities, small utilities, and isolated utilities. In addition, it was desired to select utilities with a range of economic and tax considerations representative of investor-owned, municipal, and government financing. The matrix of selected cases is shown in Table 3-1. The discussion which follows provides a brief description of the rationale for selection of location, utility characteristics, solar system configuration and solar plant ownership alternatives.

3.1.1 Location

One of the primary motivating factors in the initial case selection was to concentrate on those cases for which there is promise of early market penetration for PFDR solar electric technology. As described in an earlier report*, the southwest and south central areas of the United States were

* Solar Thermal Impact Analysis and Requirements Definition Study, Summary Report for Tasks 1, 2, and 3, Submitted to JPL by SAI, Contract 955238, 7 September 1979.

TABLE 3-1. Selected Cases for Initial Analysis

LOAD SITE UTILITY DATA	CONFIGURATION DISPATCH / CYCLE	NS NH	2.5 HR STORAGE NH		5 HR STORAGE NH		NS HYBRID			2.5 HR STORAGE HYBRID
			TOD	SF	TOD	SF	8H	ID	24 HR	DAY 8H SF
60 MW Fort Worth Municipal Utility (EPRI E Load)	BRAYTON	1								
	RANKINE	3		5	13	6	8	14	12	10
10,309 MW Phoenix Invester-Owned Utility, EPRI E	BRAYTON	2					9			
	RANKINE	4			7					
10 MW Phoenix Government Utility	BRAYTON	2					9	15	11	
	RANKINE									

FOR ALL: Penetration Levels = 5, 10, and 20 percent.

Economic Analysis = Utilities, Industries, Institutional Users.

Numbers refer to QAG runs from Table 3-4.

TOD = Time of Day Dispatch
SF = Sun Following Dispatch
ID = Incremental Hybrid Dispatch
NH = No Hybrid
NS = No Storage

selected as being favorable regions because of high insolation, medium to high electricity costs (particularly in the southwest), high industry concentration (particularly in the Texas area), and the potential for displacing oil and gas. Thus, these regions represent areas for early market penetration.

In order to address a range of solar performance characteristics in these regions it was desired to select two sites with different insolation values. From the available SOLMET Typical Meteorological Year (TMY) tapes shown in Table 3-2, Phoenix was chosen as representative of high insolation sites (average daily direct insolation greater than 7 kWh/m^2) and Fort Worth as representative of lower insolation sites (average daily insolation just under 5 kWh/m^2).

3.1.2 Utilities

A discussion of the selection criteria for each of the three utility cases is given in the following paragraphs.

Large Utilities

The Electric Power Research Institute (EPRI) has developed synthetic utility system models for use in making systematic, generic assessments of alternative new technologies and new developments in utility systems throughout the country*. The EPRI effort consisted of making a review of the characteristics of utility systems throughout the US, and then choosing characteristics of each model system to be representative of utilities in various regions of the US power system, as projected for the mid-1980's. The utility developed to be representative of the southwestern US was designated System "E". The EPRI E is a summer peaking system with predominately gas

*Synthetic Electric Utility Systems for Evaluating Advanced Technologies, EPRI EM-285, February 1977.

TABLE 3-2. SOLMET Typical Meterological Year (TMY) Weather Tape Locations

REGION 1	Boston, MA Central Park, New York, NY
REGION 2	Apalachacola, FL Miami, FL Charleston, SC Cape Hatteras, NC Sterling, VA Caribou, ME Madison, WI
REGION 3	Nashville, TN Lake Charles, LA
REGION 4	Dodge City, KS Omaha, NE Bismark, ND
REGION 5	Brownsville, TX Fort Worth, TX Columbia, MD
REGION 6	El Paso, TX Albuquerque, NM Phoenix, AZ Ely, NV Fresno, CA Santa Maria, CA
REGION 7	Great Falls, MT Medford, OR Seattle, WA

NOTE: Regions correspond to previous SAI analysis. See Figure 4-2 of Summary Report for Tasks 1, 2, and 3, 7 September 1979.

generation, and with new coal and nuclear as well. It has a predominantly 345 kV and lower transmission network, with some 500 kV. The EPRI E has loads uniformly distributed throughout the service territory, and medium transmission line lengths. The full-sized EPRI E has a generation of 45,500 MW and is suitable for regional power planning; a scaled-down version is available which SAI has utilized as representative of a single utility for this analysis.

Small Utility

For the small utility selection, the study done for JPL by Burns and McDonnell (B&M)* was utilized. The B&M effort developed seven hypothetical reference small utilities based on statistical analysis of over 2,000 small utilities throughout the United States. SAI selected one of these reference utilities for use as the representative small utility on this effort. The primary basis for the choice was consistent with the motivation described above for the selection of location; i.e., early market penetration. A utility with oil-fired generation, and hence high fuel costs, was considered the most likely candidate for early penetration by solar equipment, and therefore the 35 MW municipal utility with oil-fired generation was selected. This was expanded to a 60 MW load for the year 1990, using a scaled-down version of the EPRI E summer peaking load to represent the Fort Worth and Phoenix locations. An additional motivating selection factor was that, of the 2,000 small utilities analyzed by B&M, municipal utilities were by far the largest single category of utility in the group, comprising about half of those anlayzed. A municipal utility would therefore be most nearly representative of all small utilities.

*Assessment of the Potential of Solar Thermal Small Power Systems in Small Utilities, JPL Contract 954971, Burns & McDonnell, November 1978.

Isolated Utility

This type of utility is isolated from any external power grid, and supplies all of its own power. A typical example might be an island utility or a military base with its own power system. The example chosen was a military base, since electrical load records are kept on such bases as singular entities. Additionally, military bases are close to being self-contained communities and would thus have similar load shapes to what one would expect from an isolated utility. The load values from the Marine Corps Air Station at Yuma, Arizona, were obtained and used in conjunction with the SOLMET weather data from Phoenix, Arizona. To simulate an isolated load, the generation mix chosen for this case was constrained not to be able to purchase power from another utility nor to be able to purchase portions of large generating plants in conjunction with other utilities.

Southern California Edison Utility

To provide a perspective on the results of the synthetic utility case studies, it was decided to evaluate the worth of solar thermal electric for an actual utility. Southern California Edison (SCE) is a large, investor-owned utility which has been a leader in the implementation of alternative energy resources. SCE has high insolation sites available within a service area for which environmental impacts are of great concern, and hence is a good candidate for solar power systems. A description of the SCE utility system is provided separately in Section 7 of this report.

3.1.3 System Selection

The primary motivation behind selection of PFDR system configurations was early market penetration, maintaining consistency with the motivation for selection of location. The Rankine cycle technology is commercially available now, and was therefore selected. Hybrid and storage options were used (in addition to no-hybrid, no-storage) so that their effects

could be seen. It was also desired that an alternative technology to the Rankine be utilized in order to compare the results. The Brayton cycle was chosen, as it represents the promise of a viable, highly efficient technology for the near future. For these initial cases, no storage options were used with the Brayton cycle, as high-temperatue thermal liquid storage is not a near-term technology. The isolated government utility was considered to be a likely user of hybrid modes of operation, and therefore hybrid options were run for this case. Residual oil was assumed for fossil fuel operation.

3.1.4 Solar System Owner

Because of the flexibility of the methodology, it is possible to range across several types of solar plant ownership options to perform impact analysis with respect to a given utility. It is assumed in the analysis that the owner (which may be the utility itself) is connected to the conventional backup generation system and that all utility savings resulting from the solar generation are passed back to the owner. This provides a consistent, system-wide analysis of the benefits of the solar plant relative to both solar capital costs and the cost of backup energy supply. The selected ownership options include the central utility itself, government ownership, a range of favorable industrial financing alternatives, and small utilities (municipal or rural electric cooperatives) which buy power from the central utility. These ownership options are described in more detail in Section 3.3

3.2 SOLAR THERMAL ELECTRIC SYSTEM CHARACTERISTICS AND PERFORMANCE

The solar collector used exclusively for this analysis was the point focus distributed receiver (PFDR) parabolic dish. Both Rankine and Brayton cycles were used. The properties of PFDR concentrators, receivers, energy transport, thermodynamic cycles, and hybrid and storage configurations and dispatch strategies were described in detail in two previous reports under this contract*. The characteristics of the PFDR collector used in this analysis are summarized in Table 3-3, and a summary of the Solar Thermal Electric Performance Model (QAG) runs and some results are shown in Table 3-4. The engine efficiency curves for the open Brayton and Rankine cycles used in this analysis are shown in Figures 3-1 and 3-2. The lower curve (1980-1990) was used for the Brayton cycle calculations.

Based on the performance results categorized in Table 3-4, the annual capacity factors (CFs) are plotted in Figure 3-3. In addition, Figures 3-4 and 3-5 show the average daily solar plant output by month, and the annual average turbine output by time-of-day. The latter two figures are for the Rankine/Fort Worth cases only. Some selected aspects of these results are discussed in the following paragraphs.

3.2.1 Brayton Versus Rankine

In Figure 3-3 it can be seen for the no hybrid/no storage (NH/NS) case that the Rankine cycle performs slightly better than the Brayton (QAG runs 3 vs 1, 4 vs 2). This is as a result of choosing the lower (nearer-term) of the two Brayton efficiency curves in Figure 3-1, as well as the comparative shapes of the Brayton and Rankine curves. The Brayton curve can be seen to drop off much more rapidly in efficiency as the turbine power input is lowered below the 100 percent rated value. When the systems are operating without hybrid, there is a large part of the time when the turbine will be operating at less than its rated capacity, as can be seen from Figure 3-5 (run 3). Even with storage (6, 13), this is true. Thus, in the non-hybrid mode, the Rankine cycle can be expected to give better average performance than the Brayton cycle because of differences in part-load efficiency.

*Summary Report for Tasks 1, 2, and 3 (Sept. 1979) and Summary Report for Task 4—Methodology Development (Feb. 1980), JPL Contract #955238.

TABLE 3-3. Parabolic Dish Collector Characteristics

Characteristic	Purpose
• Dish Diameter 11 m	
• Mirror Reflectivity 0.9	
• Mirror Slope Error 3.5 mrad	Determine Receiver Intercept Factor
• Reflected Beam Pointing Error 3.5 mrad	Determine Receiver Intercept Factor
• Receiver Diameter 0.71 m	Determine Receiver Intercept Factor; Determine Receiver Thermal Losses
• Convection Loss Fraction 0.05	Determine Receiver Thermal Losses
• Reflection Loss Fraction 0.01	Determine Receiver Thermal Losses
• Conduction Loss Fraction 0.0015	Determine Receiver Thermal Losses
• Effective Temperature for Receiver Reradiation—varies with Turbine Cycle	Determine Receiver Thermal Losses
• Piping Loss Factor 0.97	
• Collector Outage Rate* 0.08	

*Outage rate includes forced outages and daytime maintenance. Routine maintenance is assumed to be scheduled when sunlight is unavailable.

TABLE 3-4. Catalog of Performance Model Executions and Results

	CYCLE	LOCATION	HYBRID	STORAGE	MULTIPLE	TURBINE EFFICIENCY CURVE USED	MAXIMUM TURBINE INPUT TEMP	RDELT	DESIGN PT TURBINE INPUT (kW)	RTO* (kW)	TAO** (10^6 kWh)	CAPACITY FACTOR	DEFOCUSED ENERGY (kWh)	HYBRID FUEL USED (10^6 kWh)
1	OB	Ft Worth	NH	NS	1	10-25 kW	871°C	-230°C	73.9	25.49	0.3809	0.157	—	—
2	OB	Phoenix	NH	NS	1	10-25 kW	871°C	-230°C	73.9	25.49	0.5580	0.230	.248	—
3	R	Ft Worth	NH	NS	1	4-22 kW	427°C	-129°C	742.7	208.4	0.3521	0.177	—	—
4	R	Phoenix	NH	NS	1	4-22 kW	427°C	-129°C	742.7	208.4	0.5087	0.256	2.75	—
5	R	Ft Worth	NH	2.5 Hr SF	1.49	4-22 kW	427°C	-129°C	498.5	139.9	0.3437	0.258	30.6	—
6	R	Ft Worth	NH	5.0 Hr SF	2	4-22 kW	427°C	-129°C	371.4	104.2	0.3306	0.333	1,951.8	—
7	R	Phoenix	NH	5.0 Hr TOD	2	4-22 kW	427°C	-129°C	371.4	104.2	0.3686	0.372	320,000	—
8	R	Ft Worth	8-Hr	NS	1	4-22 kW	427°C	-129°C	742.7	208.4	0.7366	0.371	—	1.7
9	OB	Phoenix	8-Hr	NS	1	10-25 kW	871°C	-230°C	73.9	25.49	0.9307	0.383	0.248	1.3
10	R	Ft Worth	8-Hr	2.5 Hr SF	1.49	4-22 kW	427°C	-129°C	498.5	139.9	0.5267	0.395	30.6	0.81
11	OB	Phoenix	24-Hr	NS	1	10-25 kW	871°C	-230°C	73.9	25.49	2.2045	0.908	0.248	5.8
12	R	Ft Worth	24-Hr	NS	1	4-22 kW	427°C	-129°C	742.7	208.4	1.8346	0.925	—	6.5
13	R	Ft Worth	NH	5.0 Hr TOD	2	4-22 kW	427°C	-129°C	371.4	104.2	0.2780	0.280	138,040	—
14	R	Ft Worth	ID	NS	1	4-22 kW	427°C	-129°C	742.7	208.4	0.5426	0.273	—	0.863
15	OB	Phoenix	ID	NS	1	10-25 kW	871°C	-230°C	73.9	25.49	0.7895	0.325	0.248	0.75

*Rated Turbine Output
**Total Annual Output for 10-dish system

NOTES: OB - Open Brayton, R = Rankine
All Rankine is central generation with 10 dishes per turbine; all Brayton is dispersed generation.
NH - No Hybrid; NS = No Storage; SF = Sun-Following; TOD = Time-of-Day; ID = Incremental Hybrid Dispatch.
Turbine Efficiency Curves Used: See Figures
RDELT - Difference between Turbine Inlet Temperature and Effective Receiver Temperature (for radiation loss).
Annual output is for a 10 dish system. Design point turbine input is for 1 dish in the Brayton case, and 10 dishes in the Rankine case.
Capacity Factor is computer as:

$$CF = \frac{TAO \times 0.92}{8760 \times RTO}$$ — where

CF = Capacity Factor
TAO = Total Annual Output
0.92 = Forced Outage Factor = 1-Forced Outage Rate
RTO = Rated Turbine Output

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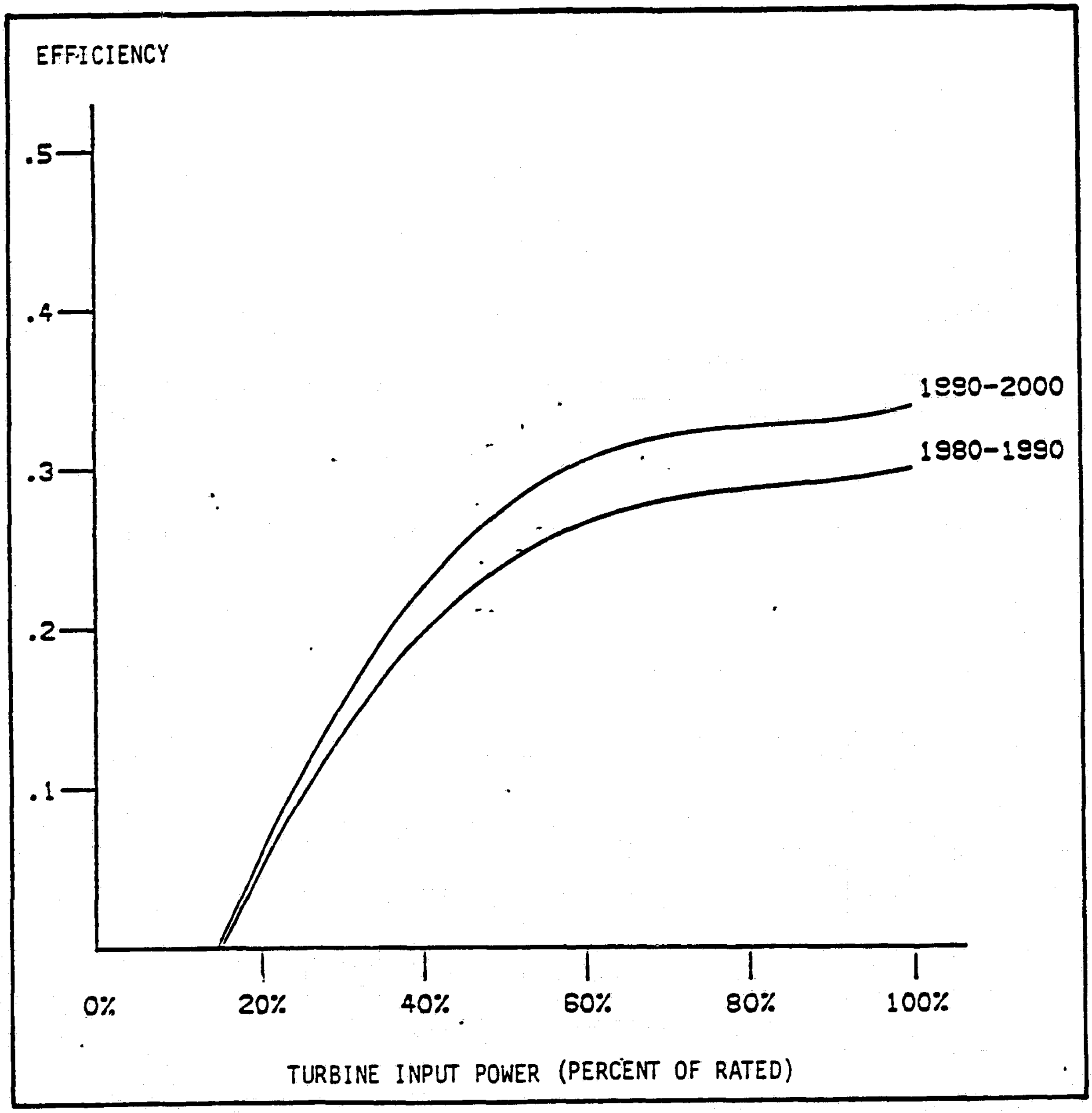

FIGURE 3-1. Open Brayton Engine Efficiency versus Power Input

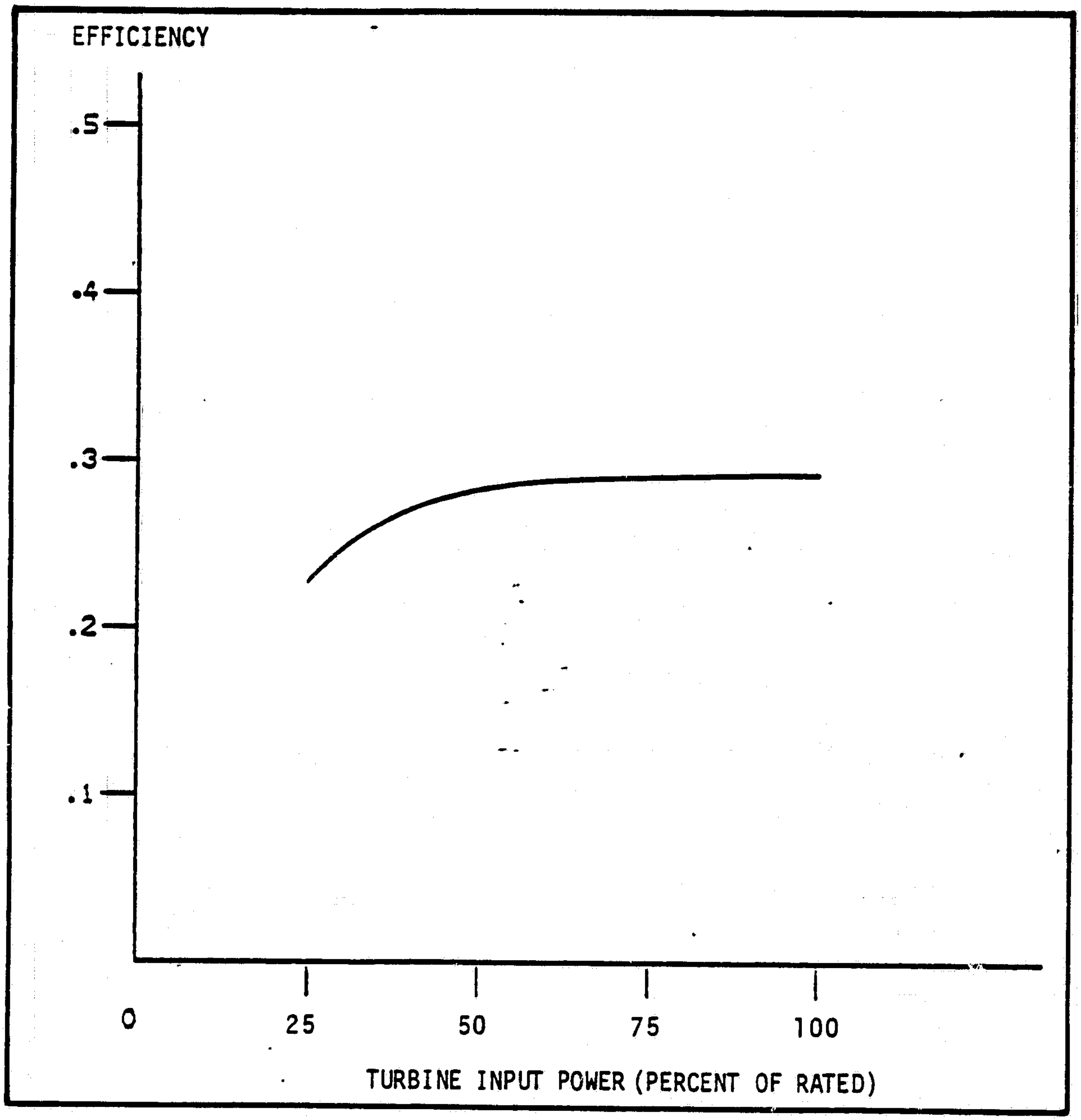

FIGURE 3-2. Organic Rankine Engine Efficiency versus Power Input

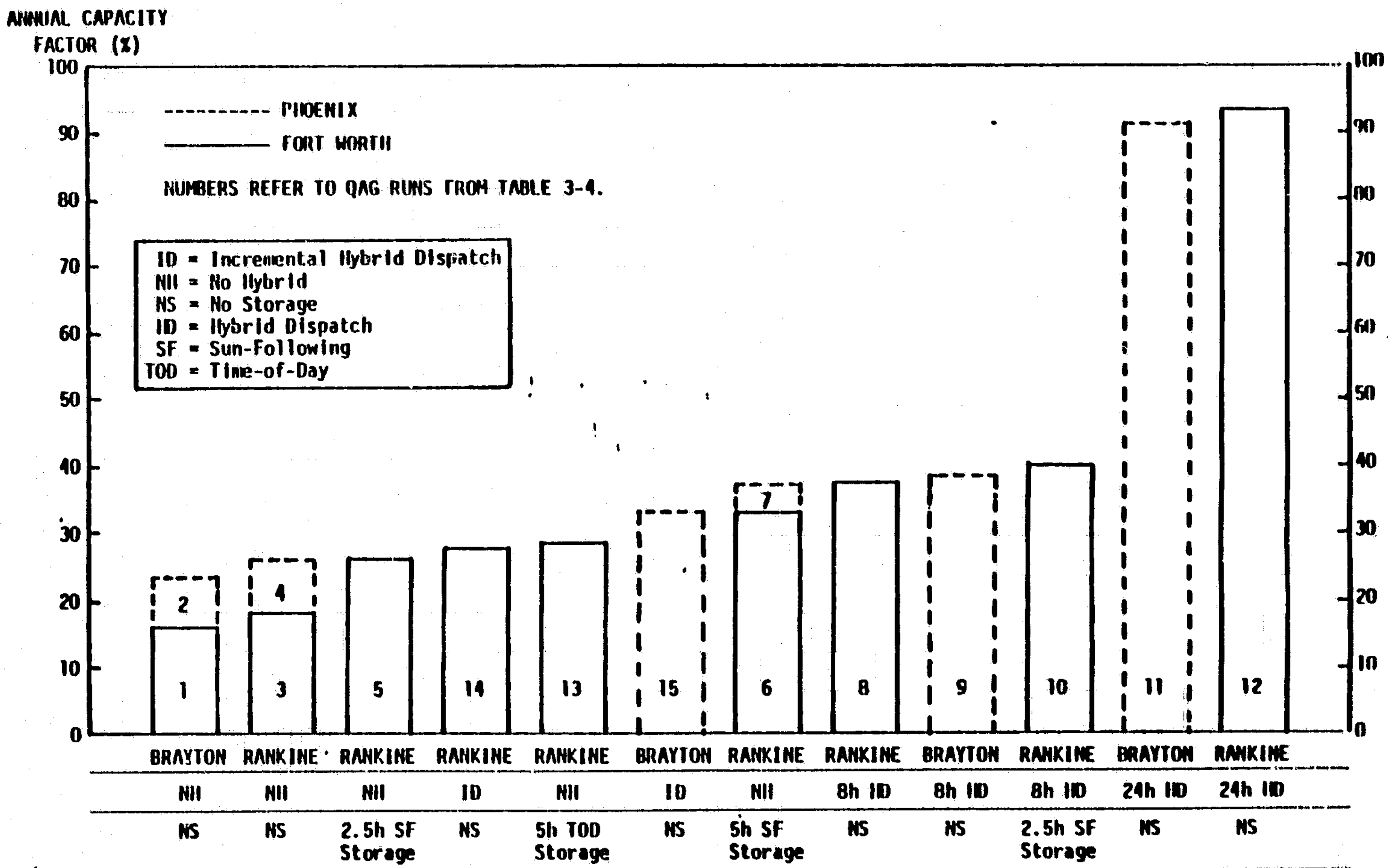

FIGURE 3-3. Annual Capacity Factors from Table 3-4 Results

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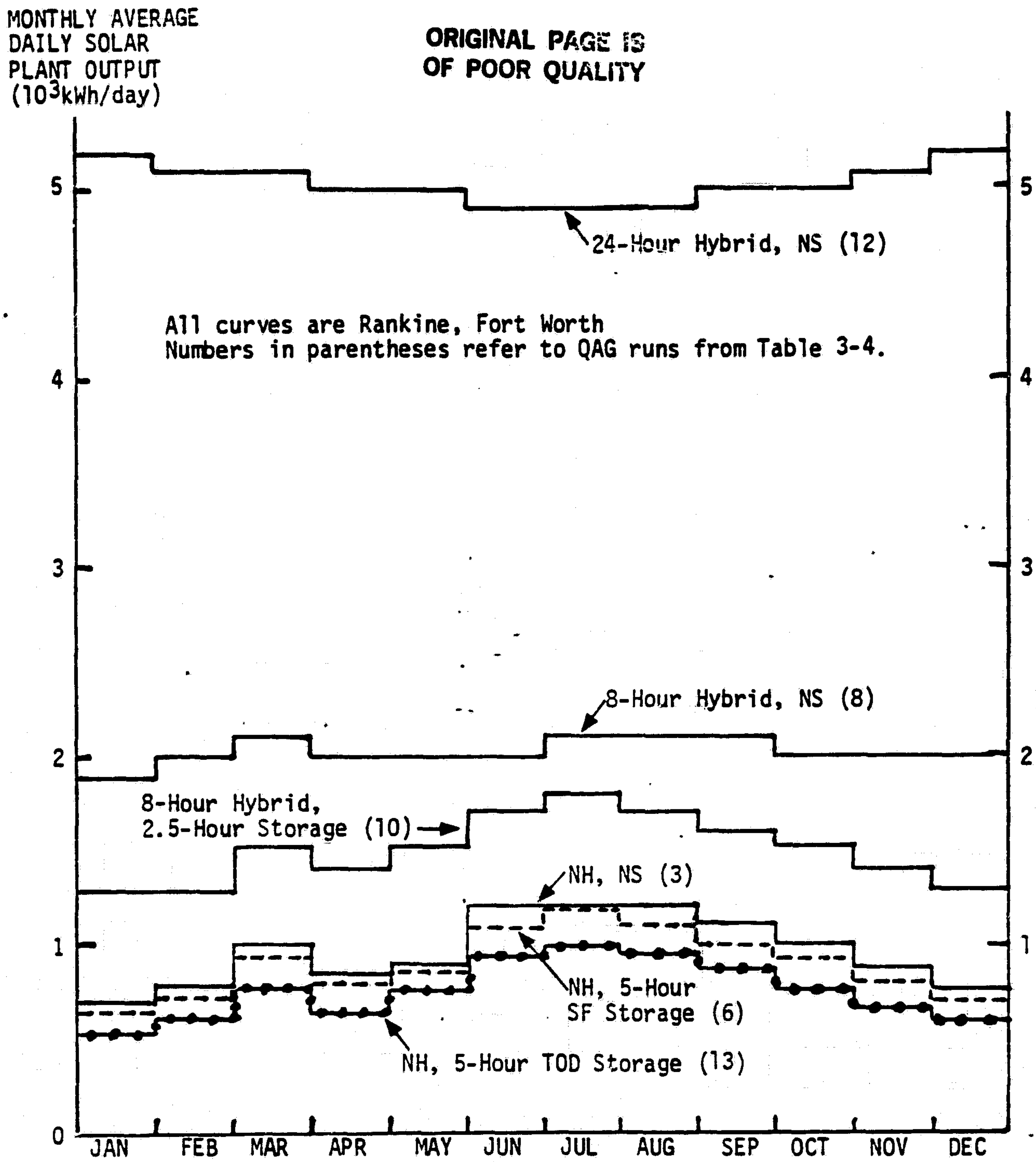

FIGURE 3-4. Average Daily Solar Plant Output by Month

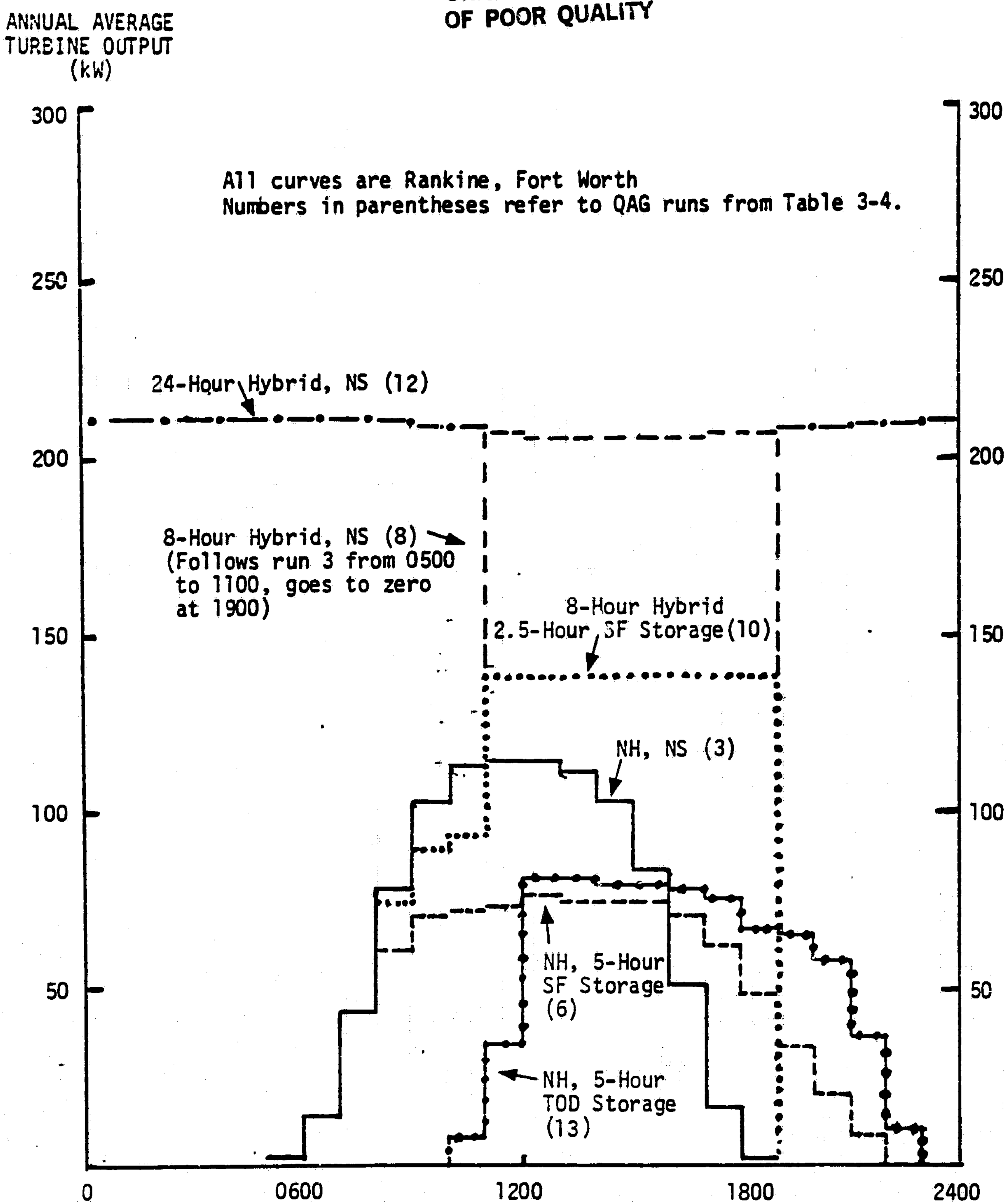

FIGURE 3-5. Annual Average Turbine Output by Time-of-Day

3.2.2 Storage

Storage is used for the Rankine cycle only. Storage subsystem characteristics are summarized in Table 3-5. From Figure 3-3 it can be seen that the capacity factors for storage are larger than for no storage (e.g., 5 or 6 versus 3, 7 versus 4). The reason for this can be seen from the equation for the capacity factor (CF):

$$CF = \frac{TAO \times 0.92}{8760 \times RTO}$$

where: TAO = Total Annual Output (MWh/y)

0.92 = Availability

RTO = Rated Turbine Output (MW).

TABLE 3-5. Storage Subsystem Characteristics

- Rankine Central Generation Only
- Input Efficiency 0.9, Output Efficiency 0.9
- 2.5 Hours Stroage, 1.5 Solar Multiple
- 5 Hours Storage, 2.0 Solar Multiple
- Sun-Following Dispatch (Turbine Priority)
- Time-of-Day Dispatch (Storage Priority before Noon, Turbine Priority after Noon)

For the storage configuration, the rated turbine input power level is set at less than the rated receiver output so that excess energy is available for storage; the solar multiple is the ratio of rated turbine input power to rated receiver output power. However, the total annual energy output is nearly the same as in the no-storage configuration, with some reduction because of storage efficiency losses and occasional collector defocus when storage is filled. Thus the storage-driven turbine is smaller but is run for a longer period of time, resulting in a higher annual capacity factor. In fact, from the equation above, it can be seen that the capacity factor with storage should be larger than that with no storage by slightly less than the solar multiple (SM). Comparison of the

QAG runs 3, 5, and 6 in Table 3-4 yields the following results:

$SM_5/SM_3 = 1.49/1 = 1.49$ $\quad$ $SM_6/SM_3 = 2.0/1 = 2.0$

$CF_5/CF_3 = 0.258/0.177 = 1.46$ $\quad$ $CF_6/CF_3 = 0.333/0.177 = 1.88$

The CF ratios can be seen to be only slightly less than the SM ratios.

The two storage dispatch strategies used in this analysis are sun-following (SF) and load-shifting or time-of-day (TOD), neither of which are through-storage methods. The SF strategy uses a turbine priority dispatch which minimizes the energy through storage (with its associated efficiency losses) and hence maximizes total energy output. The TOD strategy utilizes a storage priority dispatch in the morning, followed by turbine priority in the afternoon. The effect of storage dispatch is shown in the average daily profile in Figures 3-3, 3-4, and 3-5 (QAG runs 6 vs 13). In the TOD mode, more storage is available to meet the demand during the specified afternoon time period, but the higher total output for the SF mode is evident. The TOD dispatch time was selected based on peak demand periods for the utility loads.

3.2.3 Location

It can be seen from Figure 3-3 that the CFs at the Phoenix location are higher than those for the Fort Worth location (QAG runs 1, 3, and 6 vs 2 4, and 7, respectively). This is because Phoenix averages better than 7 kWh/m^2/day while Forth Worth averages less than 5 kWh/m^2/day.

3.2.4 Hybrid

The three hybrid options used were 8-hour, 24-hour, and incremental dispatch modes with residual oil fuel, as summarized in Table 3-6. In the first two options, the hybrid mode is used to supplement the solar receiver energy to drive the turbine at a preferred level. The hybrid mode is in effect for 8 hours in one case, and 24 hours in the other, as can be seen from Figure 3-5 (QAG runs 8 and 10 vs 12). When hybrid is operated with storage, the system draws from the receiver first, storage next, and hybrid last. This results in there being no storage remaining at the end of the 8-hour hybrid period, as can be seen from the plot of the QAG run 10 on Figure 3-5.

TABLE 3-6. Hybrid Subsystem Characteristics

- Rankine and Brayton cycles
- Boiler Efficiency 0.8
- 8 Hour Dispatch—turbine run at rated capacity 11:00am to 7:00pm
- 24 Hour Dispatch—turbine run at rated capacity 24 hours per day
- Incremental Dispatch
  - Brayton—turbine raised to full capacity if solar input exceeds 30 percent
  - Rankine—turbine raised to full capacity if solar input exceeds 20 percent

Incremental hybrid dispatch (ID) involves the use of hybrid to supplement solar collector output by bringing the turbine generator up from a part-load off-design point with low efficiency up to an operating point of higher efficiency. Thus, the hybrid fuel is used at a very high incremental heat rate by not only helping to power the turbine, but also causing the turbine to operate more efficiently. The incremental hybrid dispatch is set to initiate operation only when solar input reaches some selected threshold point, and terminates when the solar input drops below this level or surpasses a user-selected upper limit level. The utilization of the ID is not necessarily high, depending on the levels specified by the user. For example, with lower and upper levels of 20 percent and 100 percent, respectively, for the Rankine system in Forth Worth as shown in Table 3-4 and Figure 3-3 (QAG run 14 vs 3), there is a higher output with ID than with no hybrid. However, an additional sensitivity run was made with limits of 20 and 40 percent, in which there was virtually no effect on capacity factor over the no hybrid option. A brief discussion is provided in Appendix B concerning the determination of threshold and preferred turbine operating levels to optimize incremental hybrid dispatch.

The effect of hybrid for different location (insolation) characteristics can be seen in the CFs of QAG runs 2, 3, 11, and 12 plotted on Figure 3-3. Comparing runs 2 and 3, it is seen that the superior insolation at Phoenix more than offsets the lower efficiency of the Brayton versus the Rankine. This is not true for runs 11 and 12, where the addition of 24-hour hybrid removes the effects of insolation (turbine output still varies slightly due to ambient temperature variations). The Fort Worth location provides less solar energy to the turbine, but the hybrid supplement makes up the difference. Much more hybrid fuel is required for Fort Worth (QAG run 12) than for Phoenix (11), as can be seen in Table 3-4.

Another effect of hybrid operation can be seen in Figure 3-4. It was noted above that the total system output with storage is only slightly less than with no storage, primarily due to system losses in and out of storage. This small difference can be seen on Figure 3-4 (6 versus 3). However, on the same figure, a much larger difference can be seen between QAG runs 8 and 10, both of which are hybrid systems, one with storage and one without. This substantial difference is due to the fact that the hybrid serves to supplement receiver (and storage) energy up to the preferred turbine output level, which is lower (the turbine is smaller) in the case of storage as discussed previously. The storage is used up during the 8-hour hybrid period and does not extend operation beyond this period, as was previously pointed out above in reference to Figure 3-5. Thus, comparing runs 8 and 10, the addition of storage to the 8-hour hybrid mode serves to reduce the amount of hybrid fuel used (Table 3-4), but also reduces the rated turbine capacity. The CFs are not much different (Figure 3-3) so that both annual output and rated turbine capacity are reduced in the same proportion.

3.2.5 Seasonal Variations

From the well-known expression for Carnot efficiency, it can be seen that cycle efficiency depends on the temperature of the heat sink available. For the open Brayton cycle, this heat sink is ususally the ambient air, and the cycle would be expected to operate more efficiently in the winter when the air temperature is low, than in the summer when the air temperature is high. A similar effect occurs for the Rankine cycle, as shown in Figures 3-4 and 3-5. In Figure 3-4, the 24-hour hybrid system (QAG run 12) exhibits a reduced average daily output during the hot summer months. In Figure 3-5, the same is true over the daily variation of temperature. The effect is much less noticable for the 8-hour hybrid period (runs 8 and 10) because the temperature variation over the 8 hours chosen is much less severe. For the no hybrid cases (3 and 6), the seasonal temperature effects are completely dominated by increased insolation levels during the summer months. On an annual basis by month (Figure 3-4), the summer versus winter effect for cases 3 and 6 are dominated by the increase in total daily insolation during

the summer months, as is the case for 8-hour hybrid (8 and 10). This effect of seasonal insolation variation is more pronounced for the case with storage (10) than for the case without storage (8), since energy stored during the day permits the turbine to run longer during summer months.

3.2.6 Solar Electric Plant Costs

Solar electric plant costs are addressed parametrically in these initial case study analyses. A range of installed costs from 1,000$/kWe to 2,000$/kWe were evaluated for each solar system configuration. For comparison purposes, these cost ranges can be compared with estimates developed by JPL and Burns and McDonnell in Table 3-7.

TABLE 3-7. Solar Thermal Electric System Costs[6] in 1980 $/kW

	JPL[1] (1990 INSTALLATION)		B&M[2,3,4] (1985 INSTALLATION)	
	RANKINE	BRAYTON	HIGH	LOW
Collectors	591	528	1,147	371
Piping	165	-	75	27
Conversion (Turbines)	450	133	300	80
Storage[5]	144	209	135	135
Land Cost	23	23	5	
Site Preparation	64	64	490	
Other Construction Costs	-	-	1,181	
Electrical Equipment	-	-	165	
Fees (Construction Mgmt., A&E, Legal)	278	208	363	345
Contingencies (10%)	139	104	350	
Taxes	57	57	57	
Construction Overhead	24	24	44	
Controls	47	83	-	
Shipping	21	16	-	
Spares	70	52	6	
TOTAL	2,073	1,501	4,318	958

1—Antoniak, et al, A Relative Cost/Performance Analysis of Solar Thermal Electric Power Plants, JPL, Draft obtained February 1980.

2—Assessment of the Potential of Solar Thermal Small Power Systems in Small Utilities, Burns & McDonnell, November 1978.

3—Burns & McDonnell did not distinguish between costs for Rankine, Brayton, or Stirling.

4—B&M costs have been inflated from 1975 to 1980 dollars.

5—Storage is 5h thermal for JPL Rankine, 5h advanced battery for the JPL Brayton, and 2h advanced battery for the B&M estimates.

6—JPL estimates have changed since the preparation of this report.

3.3 UTILITY SYSTEM CHARACTERISTICS

Table 3-8 summarizes conventional generating plant characteristics including capacity, fuel type, heat rate, capital cost, fixed and variable O&M costs, outage rate, and maintenance requirements. Capital cost estimates include equipment, installation, startup, inventory, land, and allowance for funds during construction.

The heat rates shown are at full load; part load heat rates are actually used in the analysis. The analysis also utilizes partial capacity outage representations for the larger plants. Data for the large plants (50 MW and above, except for the 60 MW coal plant) are taken from the EPRI Technical Assessment Guide. Data for the remaining plants are based on the Burns and McDonnell study. In some cases, fixed costs are omitted for plants which are not utilized in the capacity expansion, since fixed costs for these plants do not affect the results.

The impact analyses were conducted using three generic utility systems—small municipal, large investor-owned, and small government-owned. Table 3-9 summarizes the load characteristics of the three utilities. The generation mix and capacity expansion through 1990 are summarized below for each utility.

3.3.1 Municipal Utility

Table 3-10 summarizes the characteristics of the municipal generation mix. The initial 1980 mix consists of oil and diesel units with a significant amount of purchased power from other utilities. For the expansion through 1990, the municipal is permitted to share fractional power plants with other utilities and thereby take advantage of lower municipal financing costs. In these initial case studies, no limit is placed on the number of fractional units that the municipal can purchase. Gas generation is permitted to enter the mix; nuclear, however, is excluded. Thus, the municipal chooses to add a large amount of shared coal capacity as well as some gas generation (financial assumptions are described later sections). For peaking capacity, the municipal adds most of a 3 MW diesel with low capital costs to meet the annual LOLP criterion. As discussed previously, the municipal is permitted

TABLE 3-8. Generating Plant Characteristics

GENERATING UNIT	FUEL	HEAT RATE (BTU/MWH)	CAPITAL COST ($/KW)	FIXED O&M ($/KW/Y)	VAR O&M ($/MWH)	FORCED OUTAGE RATE	SCHEDULED MAINTENANCE (WEEK/YEAR)
800 MW NUCLEAR (N)	N	10.40	960	3.25	0.82	0.15	7
800 MW COAL (WFGD)	COAL	8.31	960	2.82	2.76	0.24	5
800 MW NATURAL GAS (NG)	NG	9.2	450	2.25	0.37	0.24	5
600 MW NATURAL GAS	NG	9.4	450	2.25	0.37	0.21	5
400 MW NATURAL GAS	NG	9.5	450	2.25	0.37	0.13	5
600 MW COAL	COAL	9.167	1,000	2.32	2.76	0.21	5
400 MW COAL	COAL	9.27	1,070	2.82	2.76	0.13	5
400 MW OIL	OR*	9.40	450	2.25	0.37	0.13	5
200 MW NATURAL GAS	NG	10.05	450	2.25	0.37	0.074	3.5
200 MW OIL	OR*	9.90	450	2.25	0.37	0.074	3.5
200 MW COAL	COAL	9.785	1,190	2.82	2.76	0.074	3.5
50 MW CT	OD**	14.00	185	0.61	2.50	0.240	2

*OR - OIL RESIDUAL
**OD - OIL DISTILLATE

SOURCE: EPRI

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TABLE 3-8. Continued

GENERATING UNIT	FUEL	HEAT RATE (BTU/MWH) 100%	CAPITAL COST ($/KW)	FIXED O&M ($/KW/Y)	VAR O&M ($/MWH)	FORCED OUTAGE RATE	SCHEDULED MAINTENANCE (WEEK/YEAR)
5 MW COAL	COAL	15.63	—	—	1.5	0.06	3.5
10 MW COAL	"	15.10	—	—	1.5	0.06	3.5
20 MW COAL	"	12.41	—	—	1.5	0.06	3.5
60 MW COAL	"	11.50	—	—	1.5	0.06	3.5
5 MW OIL	OIL-DISTILLATE	15.63	—	—	3.0	0.06	3.5
10 MW OIL	"	15.10	—	—	1.5	0.06	3.5
30 MW OIL	"	12.855	—	—	1.5	0.06	3.5
10 MW CT	"	14.84	—	—	7.5	0.11	2.0
20 MW CT	"	13.60	300	0.39	7.5	0.11	2.0
0.2 MW DIESEL	OIL-DIESEL	12.00	—	—	3.75	0.10	2.0
0.3 MW DIESEL	"	12.00	—	—	3.75	0.10	2.0
0.5 MW DIESEL	"	12.00	—	—	3.75	0.10	2.0
1 MW DIESEL	"	11.89	—	—	3.75	0.10	2.0
2 MW DIESEL	"	11.39	—	—	3.75	0.10	2.0
3 MW DIESEL	"	10.625	—	—	3.75	0.10	2.0
4 MW DIESEL	"	9.91	—	—	3.75	0.10	2.0
50 MW CT	OIL-DISTILLATE	12.00	225	0.39	7.5	0.11	2.0
0.5 MW HIGH-SPEED DIESEL	OIL-DIESEL	12.00	659	22.50	3.75	0.10	2.0
3 MW HIGH-SPEED DIESEL	"	10.625	357	7.50	3.75	0.10	2.0
5 MW LOW-SPEED DIESEL	"	9.61	516	4.50	3.75	0.10	2.0
8 MW LOW-SPEED DIESEL	"	9.61	435	2.85	3.75	0.10	2.0
150 MW COMBINED CYCLE	OIL-DISTILLATE	8.50	315	1.35	5.55	0.22	3.5

NOTE: ALL COSTS IN 1980 DOLLARS.

SOURCE: BURNS & McDONNELL

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TABLE 3-9. Utility System Load Characteristics

PARAMETER	SMALL MUNICIPAL UTILITY	LARGE INVESTOR-OWNED UTILITY	GOVERNMENT UTILITY
1980 Peak Load MW	37	6,329	10
Peak Season	Summer	Summer	Summer
Load Shape	EPRI E	EPRI E	Marine Corps Air Station, Yuma
Load Factor	0.56	0.56	0.47
Annual Load Growth	0.05	0.05	—
1990 Peak Load MW	60	10,309	10
Annual LOLP Criterion	0.014	0.001	0.014

TABLE 3-10. Baseline Municipal Utility Characteristics

A. GENERATING CAPACITY

PLANT	1980 BASELINE SYSTEM		1990 BASELINE EXPANSION		
	# OF UNITS	CAPACITY (MW)	ADDITIONAL # OF UNITS	ADDITIONAL CAPACITY (MW)	TOTAL CAPACITY (MW)
1. 5 MW Oil	1	5	—	—	5
2. 10 MW Oil	1	10	—	—	10
3. 3 MW Diesel	3	9	0.8892	2.67	11.67
4. 400 MW Coal	—	—	0.0805	32.22	32.22
5. 800 MW Coal	—	—	0.0216	17.28	17.28
6. 200 MW Nat Gas	—	—	0.0259	5.18	5.18
7. 400 MW Nat Gas	—	—	0.0283	11.32	11.32
TOTALS	5	24	1.04	68.62	92.67

B. REQUIRED REVENUES IN 1990

COST ELEMENT	LEVELIZED ANNUAL REQUIRED REVENUES (K$)
Capacity	9,131
Fixed O&M	546
Variable O&M	1,290
Fuel:	
Coal	5,878
Distillate Oil	1
Natural Gas	1,308
Diesel	251
TOTAL	18,406

to add fractional peaking units so that system reliability can be consistently compared when solar generation is added; otherwise, the integer values cause fluctuations in system reliability and capital costs which can obscure the underlying relationships.

The levelized annual revenue requirements for the optimized 1990 system are also shown in Table 3-10. Load characteristics are shown in Figures 3-6 and 3-7. Capital costs and coal fuel costs are the major cost items. Diesel generation is used only for peaking and outage situations. Total levelized annual revenues are about $18M for 1990.

3.3.2 Investor-Owned Utility

Table 3-11 summarizes the characteristics of the EPRI E synthetic utility. The initial 1985 system has a 10,300 MW capacity mix of about 16 percent nuclear, 25 percent coal, 6 percent residual oil, 5 percent distillate oil, and 49 percent natural gas. Load characteristics are summarized in Figure 3-7; peak load is 8,078 MW in 1985 projected to 10,309 MW in 1990. The capacity adjustment model adds nuclear, coal, and combustion turbine capacity through 1990 for a total installed capacity of 14,747 MW. Nuclear capacity was constrained to a maximum of four 800 MW generation units. Capital costs constitute more than half of the levelized annual revenue requirements. Fue costs in 1990 are primarily coal and gas, followed by nuclear. Total levelized annual revenue requirements are about $2,881M.

3.3.3 Isolated Government-Owned Utility

The government-owned utility consists entirely of diesel generation as shown in Table 3-12. Because the small utility is not connected to a large utility grid, it is not permitted to share fractional plants with other utilities. Thus, only diesel capacity is added to meet the reliability criterion for the 10 MW peak load. Load characteristics are shown in Figure 3-8 taken from the Marine Corps Air Station in Yuma, Arizona. Levelized annual costs projected for 1990 are $500K for capacity and $400K for diesel fuel.

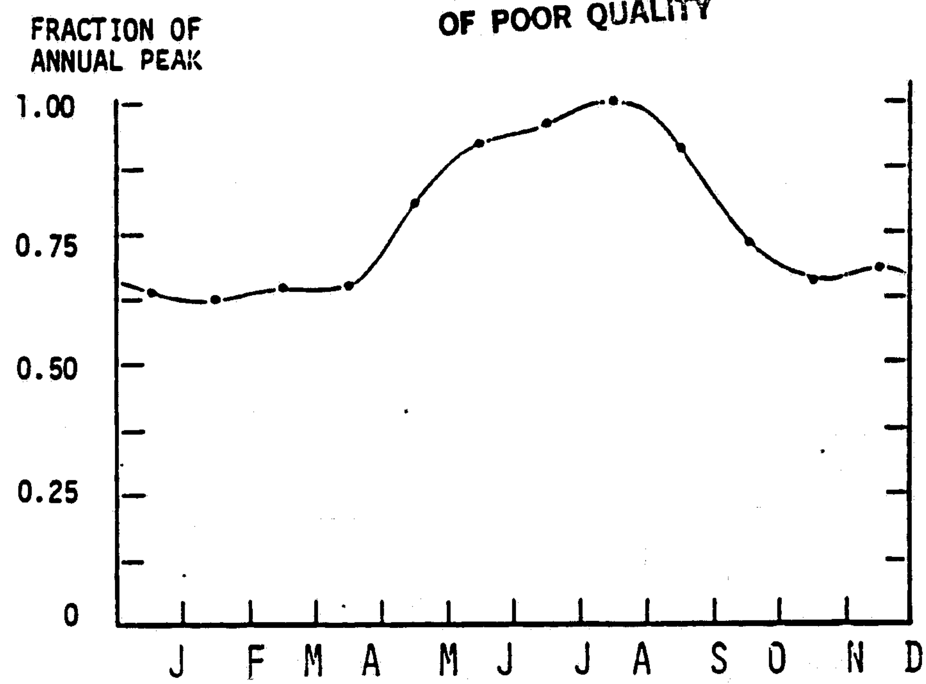

FIGURE 3-6. Load Characteristics for the Municipal and Investor-Owned Utilities (EPRI E Synthetic Utility Load)—Monthly Peak Demand Profile

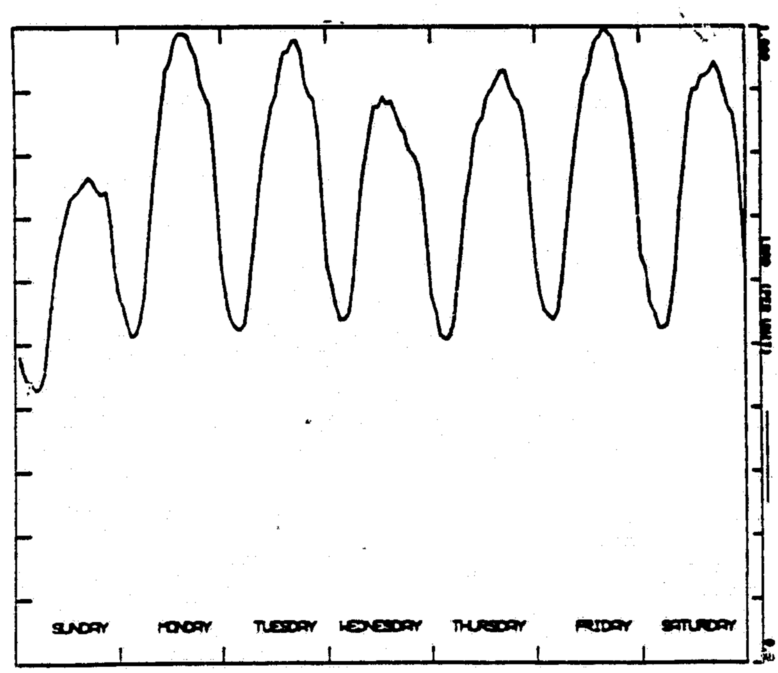

FIGURE 3-7. Load Characteristics for the Municipal and Investor-Owned Utilities (EPRI E Synthetic Utility Load)—Summer Weekly Demand Profile

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TABLE 3-11. Baseline Investor-Owned Utility Characteristics

A. GENERATING CAPACITY

PLANT	1980 BASELINE SYSTEM		1990 BASELINE EXPANSION		
	# OF UNITS	CAPACITY (MW)	ADDITIONAL # OF UNITS	ADDITIONAL CAPACITY (MW)	TOTAL CAPACITY (MW)
1. 800 MW Nuclear	2	1,600	2	1,600	3,200
2. 800 MW Coal	1	800	—	—	800
3. 800 MW Nat Gas	1	800	—	—	800
4. 600 MW Nat Gas	2	1,200	—	—	1,200
5. 400 MW Nat Gas	2	800	—	—	800
6. 600 MW Coal	2	1,200	—	—	1,200
7. 400 MW Coal	1	400	3.254	1,301.62	1,701.62
8. 400 MW Oil	1	400	—	—	400
9. 200 MW Nat Gas	11	2,200	—	—	2,200
10. 200 MW Oil	1	200	—	—	200
11. 200 MW Coal	1	200	—	—	.200
12. 50 MW Combustion Turbine	10	500	24.907	1,245.35	1,745.35
TOTALS	35	10,300	30.161	4,146.97	14,446.97

B. REQUIRED REVENUES IN 1990

COST ELEMENT	LEVELIZED ANNUAL REQUIRED REVENUES (M$)
Capacity	1,500
Fixed O&M	83
Variable O&M	131
Fuel:	
Coal	462
Nuclear	238
Distillate Oil	1
Residual Oil	5
Natural Gas	461
TOTAL	2,881

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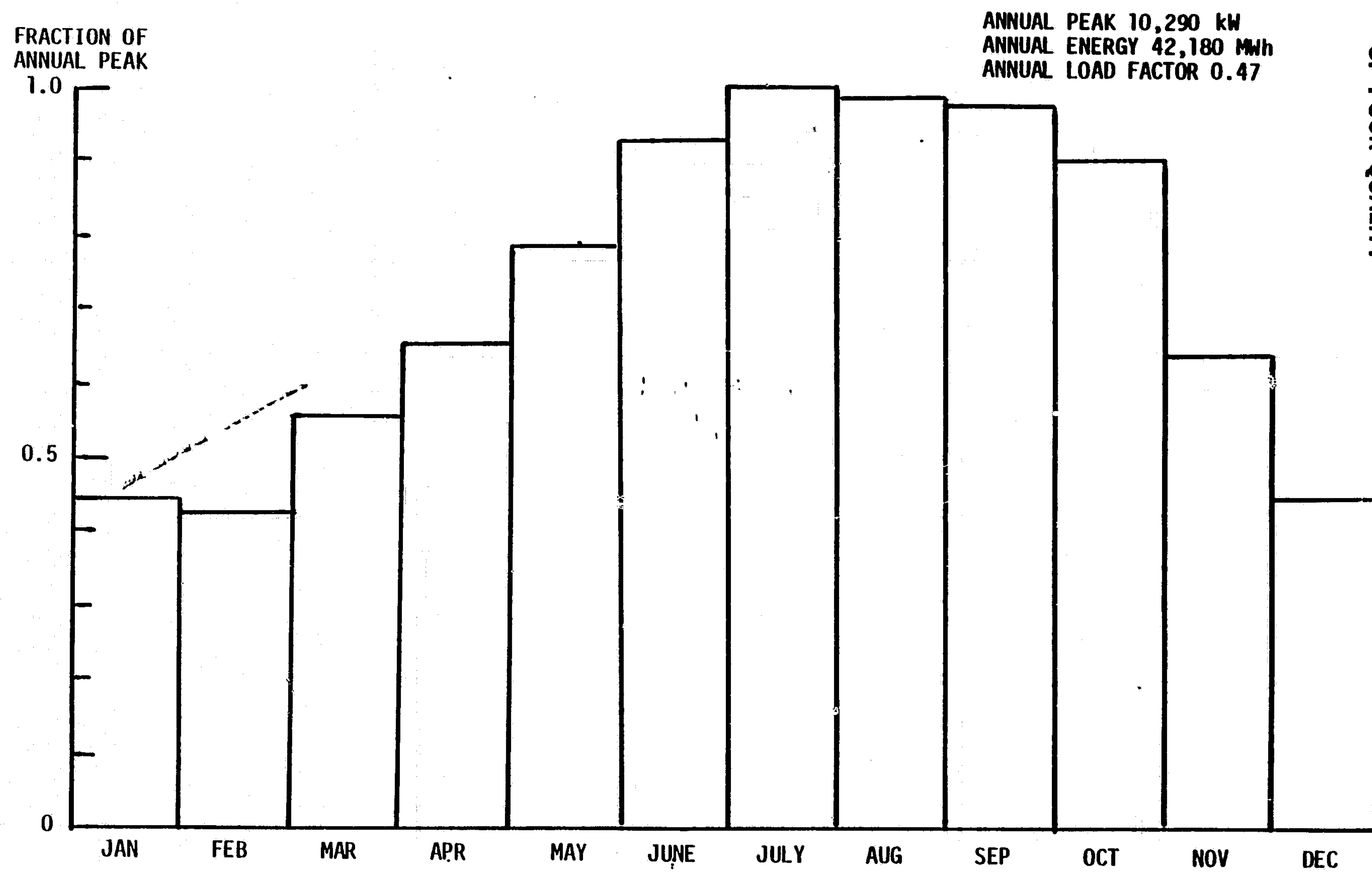
TABLE 3-12. Baseline Isolated Government Utility Characteristics

A. GENERATING CAPACITY

PLANT	1980 BASELINE SYSTEM		1990 BASELINE EXPANSION		
	# OF UNITS	CAPACITY (MW)	ADDITIONAL # OF UNITS	ADDITIONAL CAPACITY (MW)	TOTAL CAPACITY (MW)
3 MW Diesel	2	6	0.81	2.44	8.44
8 MW Diesel	—	—	0.81	6.50	6.50
TOTALS	2	6	1.62	8.94	14.94

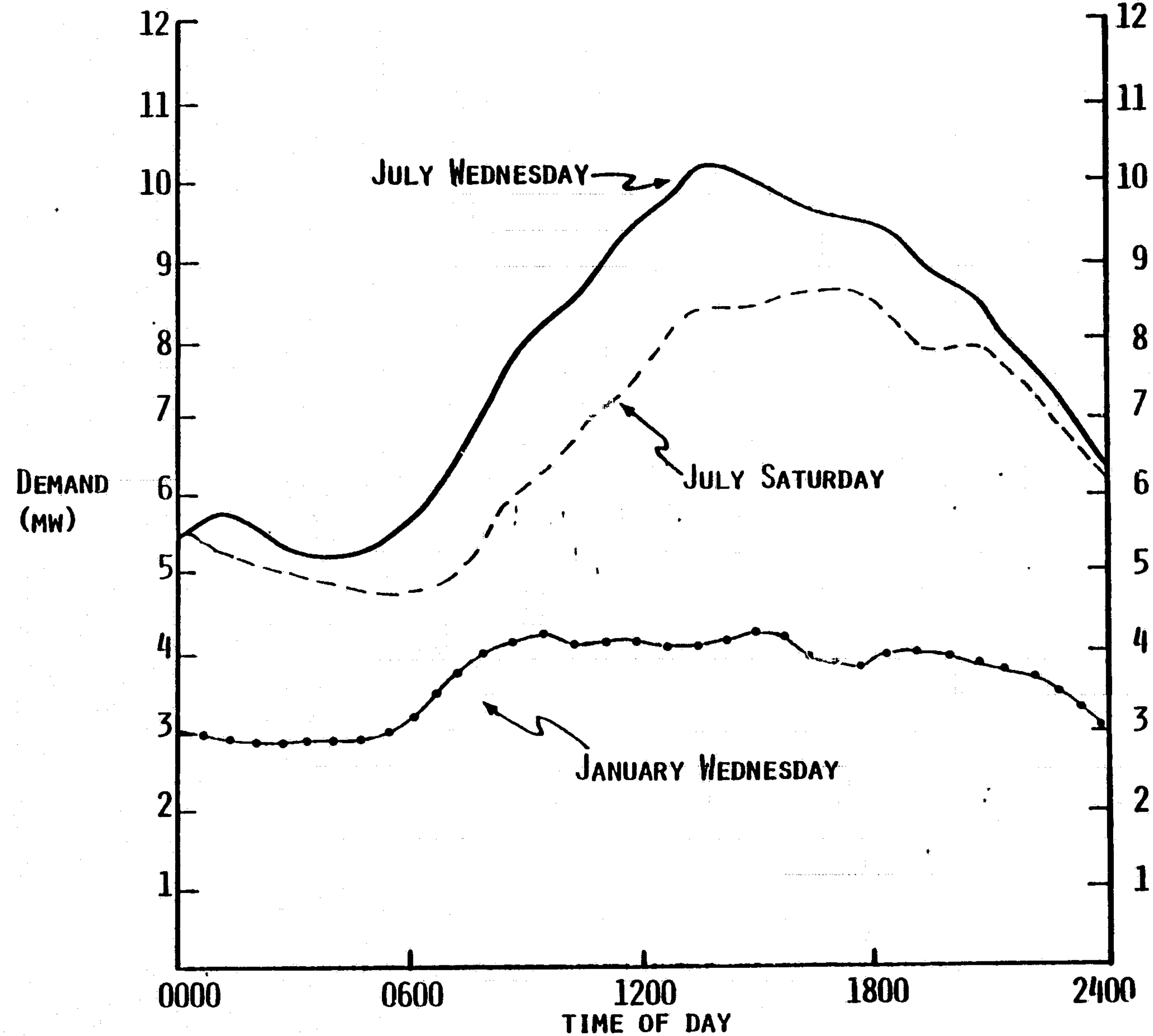
B. REQUIRED REVENUES IN 1990

COST ELEMENT	LEVELIZED ANNUAL REQUIRED REVENUES (K$)
Capacity	927
Fixed O&M	195
Variable O&M	386
Fuel:	
Diesel	6,268
TOTAL	7,775



8a. Monthly Peak Demands

FIGURE 3-8. Government-Owned Utility Load Characteristics (Yuma Marine Corps Air Station)



8b. Typical Daily Load Profile

FIGURE 3-8. Continued

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3.4 GENERAL ECONOMIC ANALYSIS ASSUMPTIONS

All cost data in this report are expressed in 1980 constant dollars. The case study analyses presented here all assume that solar is introduced into the conventional generation system in 1990. Subsequent analyses will consider other time frames.

Table 3-13 presents the assumed values of inflation and O&M and capital cost escalation for the 1990 time frame. For comparison, assumptions are also provided from the EPRI Technical Assessment Guide, the Utility Advisory Panel for the SAI South Central Study, and the SERI Solar Thermal Cost Goals Working Group. An inflation rate of 6 percent is assumed consistent with current studies and with the expectation of a stable money supply by 1990. The real escalation rates for conventional capital equipment and O&M escalation is chosen to be 0.02, consistent with the EPRI guidelines and the Advisory Panel. The lifetime for conventional power plants is assumed to be thirty years, based on current maintenance practices of most utilities. The solar plants are also assumed to have a useful life of thirty years when they are owned by the utility (the solar plant lifetime varies for other owners).

Fuel cost assumptions strongly affect the worth of solar generation. Tables 3-14 and 3-15 show the assumed fuel prices and escalation rates appropriate for the west South Central area. Only the base case fuel escalation rates have been used in this report.

3.5 UTILITY FINANCIAL ASSUMPTIONS FOR CONVENTIONAL GENERATION

There are four major types of utility ownership options in the United States. These are investor-owned utilities, municipals, rural electric cooperatives (RECs), and federal and state power authorities. The principal differences between these alternatives are the financial structure and size. Table 3-16 provides a breakdown of US utilities by type.

Financial parameters for the different utility types are shown in Tables 3-17 to 3-19. The assumed discount rate (weighted average cost of capital) is 10 percent for the investor-owned utility, 7 percent for the municipal, 9 percent for the REC, and 10 percent for the government utility, relative to an assumed inflation rate of 6 percent. These parameters are used

TABLE 3-13. General Economic Parameters

PARAMETER	ASSUMED VALUE	EPRI[1]	SERI[2]	PANEL[3]
GENERAL INFLATION	0.06	0.06		
CAPITAL COST REAL ESCALATION (NON-SOLAR)	0.02	0.02	—	0 - 0.04
O&M COST REAL ESCALATION (NON-SOLAR)	0.02	0.02	0.02	0 - 0.04
BASE YEAR FOR ALL COSTS	1980			
LIFETIME FOR ALL CONVENTIONAL POWER PLANTS	30		30	

[1] EPRI, TECHNICAL ASSESSMENT GUIDE, JUNE 1978.

[2] SERI SOLAR THERMAL COST GOALS WORKING GROUP, MAY 1980.

[3] SAI SOUTH CENTRAL STUDY, UTILITY ADVISORY PANEL, JUNE 1979.

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TABLE 3-14. Fuel Prices (1980 $/MBTU)

FUEL	ASSUMED VALUE	EIA-WEST SOUTH CENTRAL[1]	EPRI GUIDE[2]	PANEL[3] AVG	PANEL[3] HIGH	PANEL[3] LOW	REPOWERING STUDY[4]
NUCLEAR	0.7	-	0.66	0.64	1.10	0.42	0.81
COAL	1.4	1.13 - 1.36	1.43	1.55	2.25	0.50	1.24
RESIDUAL OIL	3.5	3.46 - 4.15	2.83	3.00	3.20	2.50	2.83
DISTILLATE OIL	4.7	4.25 - 5.10	3.83	4.70	5.30	4.10	3.12
DIESEL OIL	5.5	5.09 - 6.11	—	—	—	—	—
NATURAL GAS	2.3	1.75 - 2.10	2.37	2.20	2.40	2.00	—

[1]EIA, Cost & Quality of Fuels for Electric Utility Plants, DOE-EIA-0075, October 1979. Lower Prices are for March 1979; Upper Prices include 20 Percent Escalation to 1980.

[2]EPRI, Technical Assessment Guide, June 1978.

[3]SAI South Central Study, Utility Advisory Panel, June 1979.

[4]Westinghouse Electric Corporation, Solar Repowering Study, SERI Contract XP-9-8051-1, July 1979.

TABLE 3-15. Fuel Real Escalation Rates

FUEL	ASSUMED VALUE BASE	ASSUMED VALUE HIGH	EIA[1] MED	EIA[1] HIGH	EIA[1] LOW	PANEL[2] AVG	PANEL[2] HIGH	PANEL[2] LOW	DRI 1980-90	DRI 1991-2000	REPOWERING STUDY[3]
N	0.02	0.05	0.025	0.03	0.005	0.017	0.05	—	—	—	0.01 - 0.05
COAL	0.02	0.03	0.015	0.032	0.007	0.018	0.03	—	0.018	0.026	0.02
RO	0.03	0.05	0.029	0.047	0.013	0.027	0.04	—	0.035	0.030	0.04
D&DO	0.025	0.05	0.023	0.037	0.005	0.025	0.05	—	0.027	0.033	0.04
NG	0.04	0.07	0.055	0.067	0.035	0.015	0.04	—	0.074	0.047	—

N = NUCLEAR
RO = RESIDUAL OIL
D&DO = DISTILLATE & DIESEL OIL
NG = NATURAL GAS

[1]Estimated over 1975-1995 Time Period; Annual Report to Congress, DOE/EIA-0173/3, Vol 3, 1978.

[2]SAI South Central Study, Utility Advisory Panel, June 1979.

[3]Westinghouse Electric Corporation, SERI Report, July 1979.

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TABLE 3-16. Utility Ownership by Type

OWNERSHIP TYPE	% OCCURRENCE	% OF ENERGY GENERATED
Investor-Owned	24	71
Municipal	37	12
Cooperative	32	9
Government	7	8

TABLE 3-17. Financial Parameters—Municipal and Rec Utilities

PARAMETER	ASSUMED VALUE MUNICIPAL	ASSUMED VALUE REC	SERI STCGWG[1] MUNICIPAL	SERI STCGWG[1] REC	PANEL[2] MUNICIPAL	REA[3] REC
Cost of Debt	0.07	0.09	0.04	0.08	0.06 - 0.08	0.09
Insurance and Other Payments/Total Cost	0.02[4]	0.02[5]	0.02	0.02	—	—
Tax Rate	—	—				
Plant Service Life	30	30				

[1]SERI Solar Thermal Cost Goals Working Group, May 1980 (1990 Cost of Debt Converted to 6 percent Inflation Rate).

[2]SAI South Central Study, Utility Advisory Panel, June 1979.

[3]Suggested by D. Olsen, REA, 1979.

[4]Assumed to be 0.0125 for solar plant ownership

[5]Assumed to be 0.0025 (insurance only) for solar plant ownership.

TABLE 3-18. Financial Parameters—Government Installations

INVESTMENT PERIOD	=	30 YEARS
RATE OF RETURN	=	0.10
TAX RATE	=	0
DEPRECIATION	=	NONE
PROPERTY TAX AND INSURANCE	=	0.0025

TABLE 3-19. Financial Parameters—Investor-Owned Utility

PARAMETER	ASSUMED VALUE	EPRI GUIDE[1]	PANEL[2] AVG	PANEL[2] HIGH	PANEL[2] LOW	SERI STCGWG[3]
INSURANCE/TOTAL COST	0.0025	0.0025	0.0025	0.006	—	0.02
PROPERTY TAX/TOTAL COST	0.02[4]	0.02	0.019	0.025	0.007	
EFFECTIVE INCOME TAX RATE	0.5	0.5	0.475	0.51	0.42	0.48
INVESTMENT TAX CREDIT	0.10	0 - 0.10	—	—	—	0.10
PLANT SERVICE LIFE	30					30
PLANT TAX LIFE	24					24
DEBT/CAPITALIZATION	0.5	0.5	0.50	0.56	0.45	0.5
PREFERRED STOCK/CAPITALIZATION	0.15	0.15	0.12	0.15	0.09	0.5
COMMON STOCK/CAPITALIZATION	0.35	0.35	0.38	0.44	0.29	
ROR ON DEBT	0.080	0.080	0.088	0.095	0.075	0.11
ROR ON PREFERRED STOCK	0.085	0.085	0.088	0.095	0.075	0.18
ROR ON COMMON STOCK	0.135	0.135	0.144	0.150	0.13	

[1]EPRI Technical Assessment Guide, 1978.

[2]SAI South Central Study, Utility Advisory Panel, June 1979.

[3]SERI Solar Thermal Cost Goals Working Group, May 1980 (1990 ROR Converted to 6 percent inflation rate).

[4]Solar plants are assumed to be exempt from property taxes.

in the capacity adjustment model to determine the conventional generation mix so as to minimize fixed and variable costs. Thus, the utility financial parameters strongly affect the worth of the solar system for all solar plant ownership alternatives, since the differential utility savings are assumed to be passed on to the solar plant owner. Financial assumptions for the owner are described in the following section. In cases where the owner is the utility itself, the utility financing parameters are used except for parameter variations for solar system tax credit, property tax, and insurance.

3.6 SOLAR PLANT OWNERSHIP ALTERNATIVES

Plant ownership alternatives considered in these analyses include the utility itself as well as various industrial, commercial, and institutional users. Potential users or market areas are segmented and described based on purchase criteria, not physical characteristics such as facilities, land area, product line, etc. This permits the evaluation of diverse market areas having similar purchase criteria.

Financial parameters for the industrial/commercial solar plant ownership alternatives are summarized in Table 3-20. A description of the corresponding purchase decision criteria is provided in Table 3-21. Utility and federal ownership assumptions are as described in the previous section.

Solar plant annual O&M cost as a fraction of installed capital cost is assumed to be 0.0131 for the investor-owened utility, 0.0068 for the municipal, and 0.01 for all other ownership options. The methodology automatically performs a sensitivity analysis on solar plant O&M, tax credits, and annual property tax and other costs for each ownership option.

TABLE 3-20. Industrial and Commercial Financial Parameters

PURCHASE SITUATION	PROCESS ELECTRICITY			FACILITY ELECTRICITY		
	#1	#2	#3	#4	#5	#6
Investment Period	30	30	30	6	5	4
Rate of Return	0.10	0.15	0.20	0.12	0.12	0.12
Depreciation (Y)	DBB	DBB	DBB	150%	150%	150%
Depreciation Period (Y)	10	10	10	10	10	10

ALL INDUSTRIES:

- Effective Tax Rate = 0.50
- Property Tax Rate = 0.02
- Annual Insurance = 0.0025
- Salvage Value = 0
- Equity Fraction = 1.0 (Loans, Bonds not Explicitly Calculated)
- Investment Tax Credit = 0.20
- Solar Plant O&M Fraction = 0.01

TABLE 3-21. Industrial and Commercial Purchase Decision Criteria

1. BEST CASE LARGE MANUFACTURER, ELECTRIC POWER CRITICAL TO PROCESS
   - Manufacturing process has large electric energy requirements.
   - The major corporation has most of the capital available and can obtain financing at favorable rates.
   - On-site generation is viewed by the IRS as equipment for rapid depreciation.
   - The manufacturer is in business to stay and uses life cycle cost criteria. Immediate cash flow problems are not a major issue.
   - The purchase decision criteria are based on anticipated power shortages and escalation of utility prices. The manufacturer is seeking to supplement his power supply with on-site generation, in cooperation with the local utility. The investment is viewed as supportive of the primary business area, therefore, justifying a below average rate of return.
2. AVERAGE CASE LARGE MANUFACTURER, ELECTRIC POWER CRITICAL TO PROCESS
   - Conditions are the same as #1.
   - The purchase decision criteria include the perception that on-site solar has some risk because of the newness of the technology and size of the investment, therefore requiring a higher rate of return. Alternatively, purchase criteria reflect only a moderate interest in on-site generation as being outside of the primary business area.
3. LARGE MANUFACTURER, ELECTRIC POWER CRITICAL TO PROCESS
   - Conditions are the same as #1.
   - Purchase criteria reflect low interest in power generation and a higher than usual risk. This results in the need for a high rate of return.
4. COMMERCIAL FACILITY, OWNER OCCUPANT
   - Corporation plans to invest in a new facility.
   - On-site generation is viewed as part of the building structure rather than as process equipment. This results in a longer depreciation period relative to the investment period.
   - Owner-commissioned new construction offers the potential for longer term investment at normal rates of return.
5. COMMERCIAL FACILITY, INVESTMENT IN NEW SITE
   - Criteria for siting includes cost and availability of electric power.
   - On-site generation depreciated as structure rather than equipment.
   - New facility investment requires 5-year payback.
6. COMMERCIAL FACILITY, COMPETITIVE INVESTMENT
   - Conditions are the same as #4.
   - The new plant must have at least a 4-year investment payback because of internal competition for limited corporate funds.

SECTION 4

MUNICIPAL UTILITY RESULTS

SECTION 4

MUNICIPAL UTILITY RESULTS

This section describes selected results for the small municipal case study impact analyses. A range of storage and hybrid solar plant configurations were evaluated using Fort Worth meteorological data. The objective of these initial analysis studies was to evaluate the impacts of solar plants on conventional generation capacity and energy production and to assess the economic value of alternative solar plant configurations. The results are discussed in the following categories:

- Overview of Total Solar System Savings
- Capacity Impacts
- Fuel Savings
- Capital Cost Savings
- Solar System Breakeven Cost
- Solar System Net Worth

4.1 SOLAR SYSTEM SAVINGS

Total savings of fixed and variable conventional generation costs are summarized in Figure 4-1 for the various solar plant configurations and penetration levels. Savings are expressed in terms of levelized annual revenue savings to the utility per unit kW of solar generation. As expected, the savings per solar plant decreases substantially at higher penetration levels. This is because the value of solar generation saturates at higher penetration as less peaking generation and more intermediate generation is displaced and as the load-correlated reliability benefits of solar decrease.

4.1.1 Storage

The value of the solar system increases as storage is added. This is because the same rated solar capacity supplies a greater amount of energy (has a higher capacity factor) and also because a more reliable capacity credit can be taken during summer afternoon and evening peak load periods. The sun-following, turbine-priority dispatch strategy provides slightly greater revenue savings than the time-of-day dispatch strategy. This is because the sun-following strategy maximizes the total energy output of the

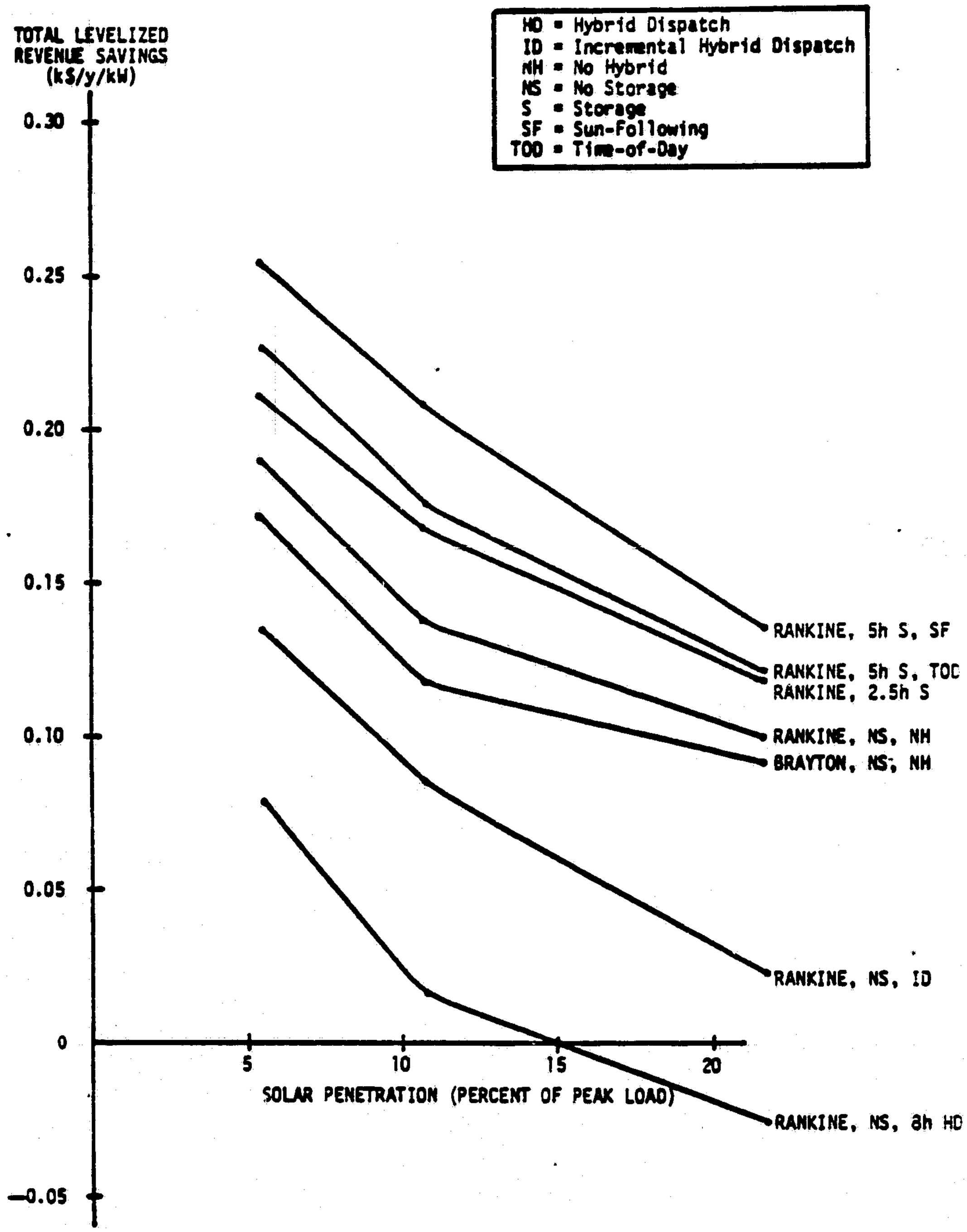

FIGURE 4-1. Solar System Savings—Municipal Utility

solar system, which energy has more value for this utility than time-of-day dispatch with its greater output during peak load periods but less total energy production.

4.1.2 Hybrid

The value of the solar generation also increases when hybrid capability is utilized. It should be noted that the savings shown for the hybrid configurations have subtracted off the cost of hybrid fuel. After accounting for these hybrid fuel costs, it turns out that the 24-hour hybrid system provides a negative net revenue savings, and the 8-hour hybrid system performs poorly. Thus, the additional reliability credit obtained by maintaining hybrid capability does not justify the added fuel expense for continuous hybrid dispatch—both the 8-hour and 24-hour dispatch effectively operate hybrid as a non-economic loading of peaking-type generation with high variable costs relative to cheaper coal generation. Thus the 8-hour and 24-hour hybrid dispatch systems were not investigated further in these analyses.

Two alternative dispatch strategies which make more effective use of hybrid capability include incremental hybrid dispatch and peak-shaving hybrid dispatch. Incremental dispatch maximizes the additional hybrid-generated electricity value per unit hybrid fuel consumption (see Section 3.2 and Appendix B). Peak-shaving dispatch essentially uses the hybrid system as a peaking unit, and requires knowledge of the instantaneous utility load and conventional plant availability. This peak-shaving strategy has not been investigated in these initial case study analyses, although it now appears to be the most effective use of hybrid for utilities with baseload generation. Peak-shaving dispatch will be investigated in future analyses.

4.2 CAPACITY IMPACTS

Capacity impacts for the various solar plant configurations are summarized in Table 4-1. In general, the solar plants displace diesel peaking generation, fractional 400 MW coal units, and also gas turbine capacity at higher penetration. However, the displaced 400 MW coal units are substituted by adding fractional 800 MW coal units, reflecting a

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TABLE 4-1. Solar Capacity Displacement—Municipal Utility

SOLAR PLANT	SOLAR PENETRATION (% PEAK LOAD)	CAPACITY DISPLACED					
		3 MW DIESEL	400 MW COAL	800 MW COAL	400 MW GAS	200 MW GAS	TOTAL (MW)
BRAYTON No Storage No Hybrid	5.4	4.092	6.28	-7.2	1.36	—	4.53
	10.9	3.551	9.32	-8.88	-0.16	1.3	5.13
	21.7	3.425	4.72	-3.68	2.6	—	7.07
RANKINE No Storage No Hybrid	5.4	4.436	7.8	-7.2	—	-0.16	4.88
	10.9	4.267	7.8	-7.2	—	1.24	6.11
	21.7	2.570	4.72	-1.92	1.30	1.08	7.75
RANKINE 2.5 Hours Storage No Hybrid	5.4	3.685	7.8	-7.2	-0.16	1.32	5.45
	10.9	3.712	7.8	-7.2	1.24	1.32	6.87
	21.7	0.394	1.68	1.6	5.36	-1.4	7.63
RANKINE 5 Hours Storage No Hybrid	5.4	3.76	9.32	-8.88	-0.16	1.3	5.34
	10.9	3.83	7.80	-5.44	1.08	1.3	8.57
	21.7	-2.48	0.16	5.04	6.76	-1.52	7.96
RANKINE 5 Hours Storage Time-of-Day Dispatch No Hybrid	5.4	3.65	9.32	-8.88	-0.16	1.3	5.21
	10.9	3.17	4.72	-3.68	1.24	1.3	6.76
	21.7	-4.07	-2.88	6.80	5.36	-0.44	4.78
RANKINE No Storage 8 Hour Hybrid Dispatch	5.4	4.20	7.8	-7.2	-0.16	1.3	5.97
	10.9	2.84	4.72	-1.92	1.08	1.3	8.03
	21.7	0.07	1.68	3.28	6.76	-1.52	10.30
RANKINE No Storage Incremental Hybrid Dispatch	5.4	3.75	7.8	-7.2	-0.16	1.3	5.52
	10.9	3.29	4.72	-3.68	2.6	—	6.97
	21.7	-1.86	0.16	3.28	5.36	-0.1	6.88

re-optimization of the conventional generating mix for the solar-modified load curves. Thus, only a small amount of net coal capacity is displaced. Some peaking capacity is also displaced, but the actual magnitude decreases at higher penetration levels as more coal and gas are displaced. In fact, for the 5-hour storage configuration at 20 percent penetration, peaking capacity is added, with a significant reduction in coal and gas capacity.

In general, it can be seen that the total MW capacity displacement, when normalized by the solar capacity, decreases at higher penetration levels. This is to be expected as the peak load solar capacity benefits saturate for the higher penetration levels. The storage and hybrid configurations displace somewhat greater total capacity then the no-storage, no-hybrid configurations. More importantly, however, the type of capacity displaced changes from predominately peaking diesel units to significantly more coal and gas for the storage and hybrid configurations.

It can be seen that the total MW capacity displaced by solar is a meaningless measure without specifying the type of capacity displaced. This is because different types of capacity have quite different fixed costs, variable costs, and reliability. For example, the effective load carrying capability of combustion turbines is lowered because of their higher forced outage rates; thus, displacing 1 MW of combustion turbine has less true capacity impact than displacing the same 1 MW of a unit with higher reliability (e.g., gas). This reliability effect could be normalized out by expressing solar capacity displacement in terms of its effective load carrying capability (defined as the MW capacity of an equivalent, perfectly reliable plant which yields the same LOLP). However, the value of the capacity displacement also varies tremendously depending on the type of capacity displaced. For example, capital cost alone ranges from 185$/kW for combustion turbines to 960$/kW for large coal plants.

Similarly, the capacity displacement cannot be evaluated independent of the associated fuel savings. Thus, the re-optimized conventional mix for different types and amounts of solar may displace peaking capacity, or increase peaking capacity and displace coal capacity, or replace one type of coal plant by another, etc.—the resulting mix is selected so as to minimize

total fixed and variable costs. Thus, at one solar penetration level the major savings may result from reduced diesel fuel consumption; conversely, at higher penetration levels the major savings may result from coal capacity displacement with an actual increase in diesel fuel consumption.

It should also be noted for the small municipal utility that capacity impacts tend to be much more extreme than for larger utilities. This is because total installed capacity consists of only a few generating units, so that small changes in the load curves can significantly modify the optimum capacity mix. Moreover, in some cases total costs are not highly sensitive to variations from the optimum mix, as in the substitution of one type of coal capacity for another.

4.3 FUEL SAVINGS

Fuel savings resulting from solar generation are summarized in Figures 4-2 and 4-3 for the Rankine configurations without and with storage, respectively. Other configurations display similar characteristics. For comparison, capital, O&M, and total cost savings are also shown.

For the municipal utility, the primary form of fuel savings is coal. This is because the optimized mix uses primarily coal generation. At higher penetration levels, a significant amount of natural gas fuel is also displaced. Diesel fuel savings are actually negative; i.e., slightly more diesel is used for peaking generation after solar enters the mix. Thus, solar has little impact on oil consumption, since coal and gas represent the major fuels in the optimized mix.

As penetration level increases, coal displacement decreases only slightly since this is the predominant form of baseload and intermediate generation. A significant amount of natural gas is displaced at all penetration levels. Oil and diesel generation change very little with penetration.

The storage configuration displaces more coal and less gas per unit solar capacity than the no-storage system. This is to be expected since the 5-hour storage system displaces more baseload capacity.

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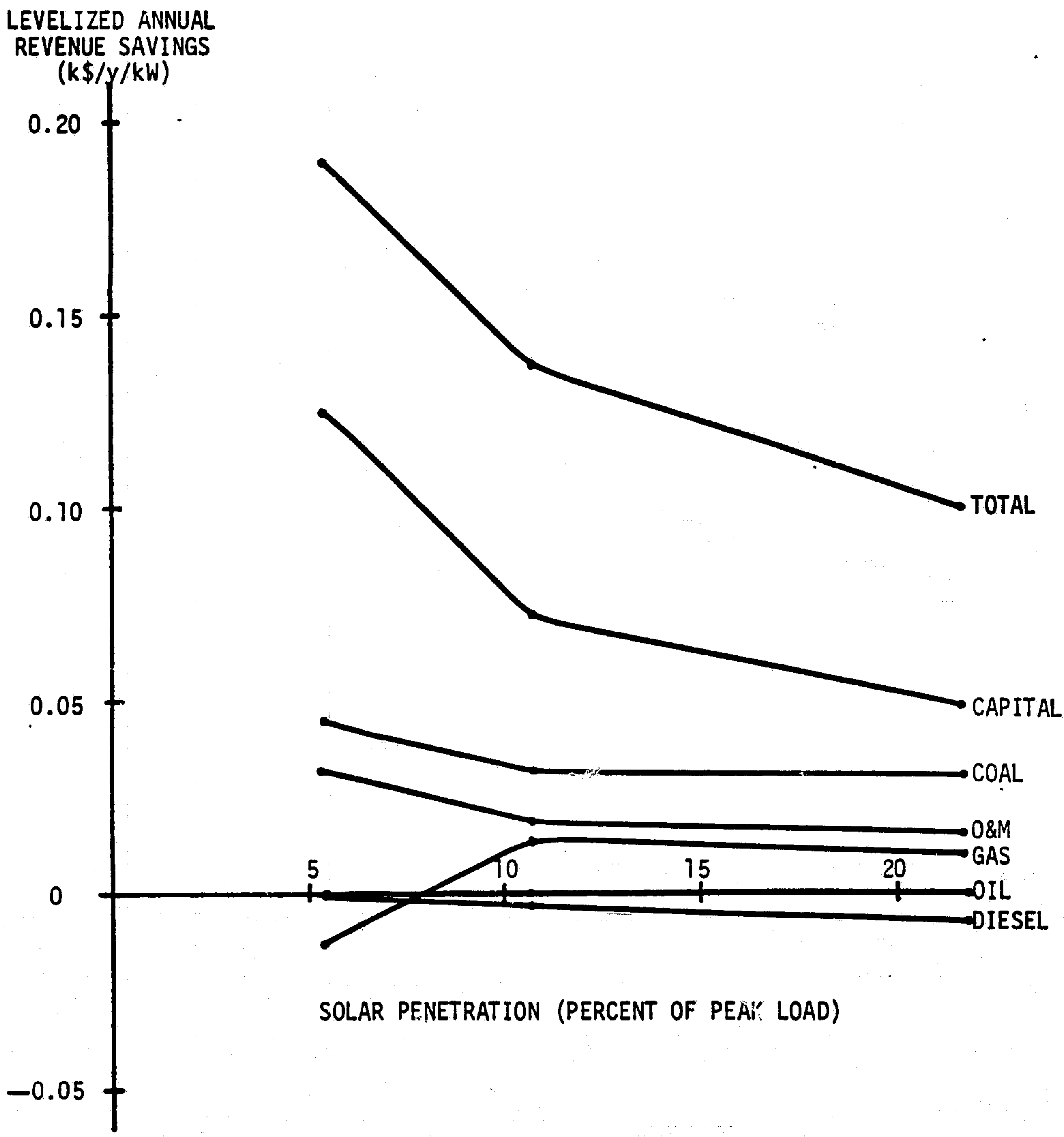

FIGURE 4-2. Solar System Savings—Municipal Utility
Rankine, No Storage, No Hybrid
Fuel Cost Breakdown

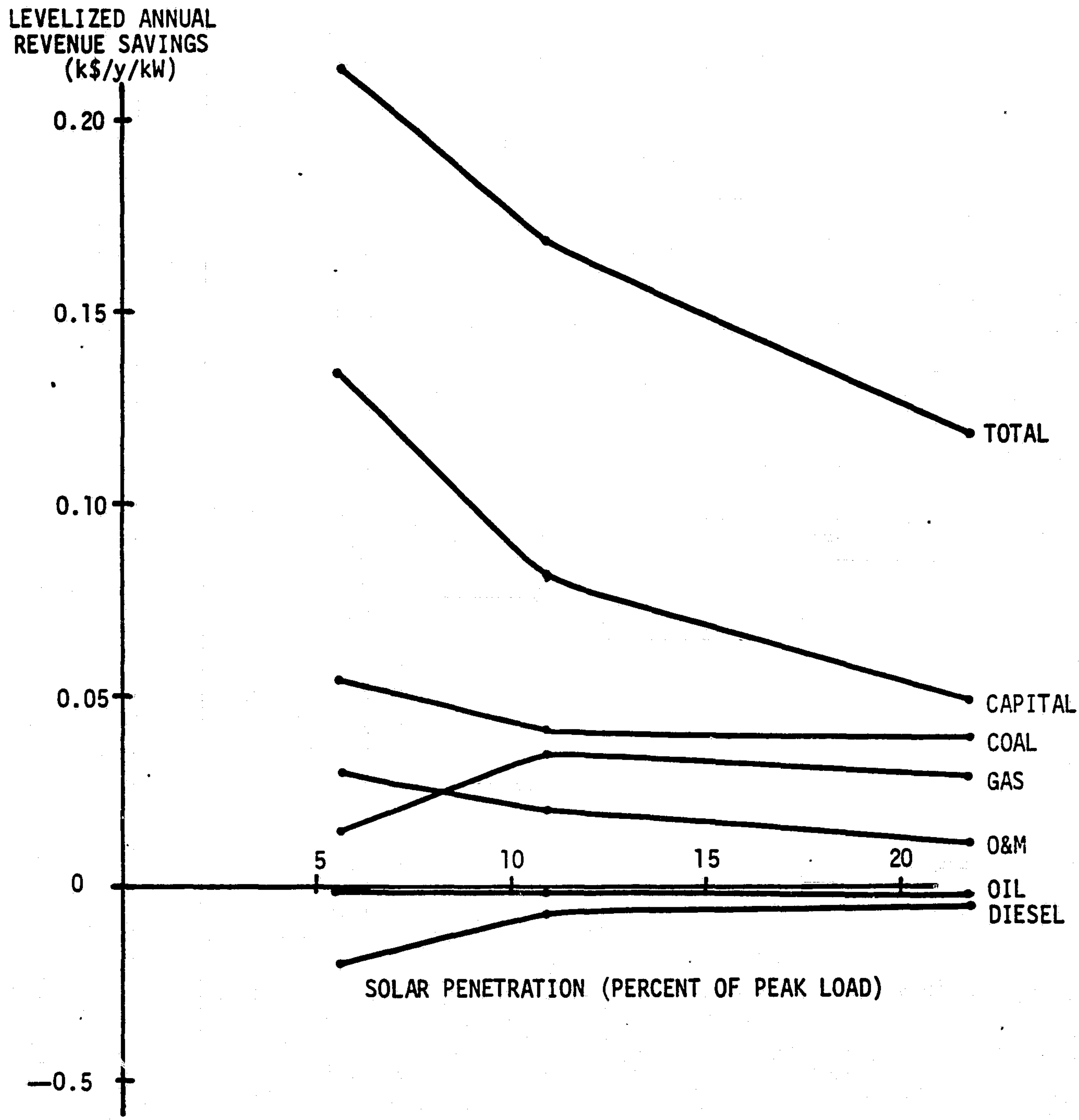

FIGURE 4-3. Solar System Savings—Municipal Utility
Rankine, 2.5 Hour Sun-Following Storage, No Hybrid
Fuel Cost Breakdown

4.4 CAPITAL COST SAVINGS

Capital cost savings for the Rankine no-storage analysis are broken out in Figure 4-4. Other solar system configurations show similar characteristics as indicated previously in Table 4-1. About half of the total capacity savings derives from displacement of 400 MW coal capacity after accounting for the addition of 800 MW coal capacity. The remaining capacity savings results from displaced diesel peaking generation.

In most cases, the value of solar to a conventional utility consists primarily of fuel savings. This is especially true for larger utilities with a broader mix of generation types (see Section 5). For this municipal utility, the solar capital cost savings are in the same range as the total fuel savings. This is because the solar plants displace capital-intensive coal capacity as well as diesel peaking units, while at the same time the fuel savings derive primarily from relatively cheap coal generation. It should be mentioned that the capacity savings are determined from a detailed reliability analysis for the solar-subtracted utility load over a single typical meteorological year, and hence some fluctuations may be expected from year-to-year. This is not accounted for in the reliability analysis.

4.5 SOLAR SYSTEM BREAKEVEN COST

Based on the total revenue savings to the utility as summarized previously in Figure 4-1, the solar system breakeven cost can be computed for the various plant ownership alternatives. This breakeven cost analysis assumes that the net utility savings are passed on to the solar plant owner.

Figure 4-5 summarizes the solar plant breakeven costs in the case of ownership by the municipal utility itself. Because of favorable municipal financing conditions, the breakeven costs are quite high. For example, at 10 percent penetration the breakeven costs are:

- Brayton, No Storage 2.04$/W
- Rankine, No Storage 2.37$/W
- Rankine, 2.5 Hour Storage 2.91$/W
- Rankine, 5.0 Hour Storage 3.59$/W.

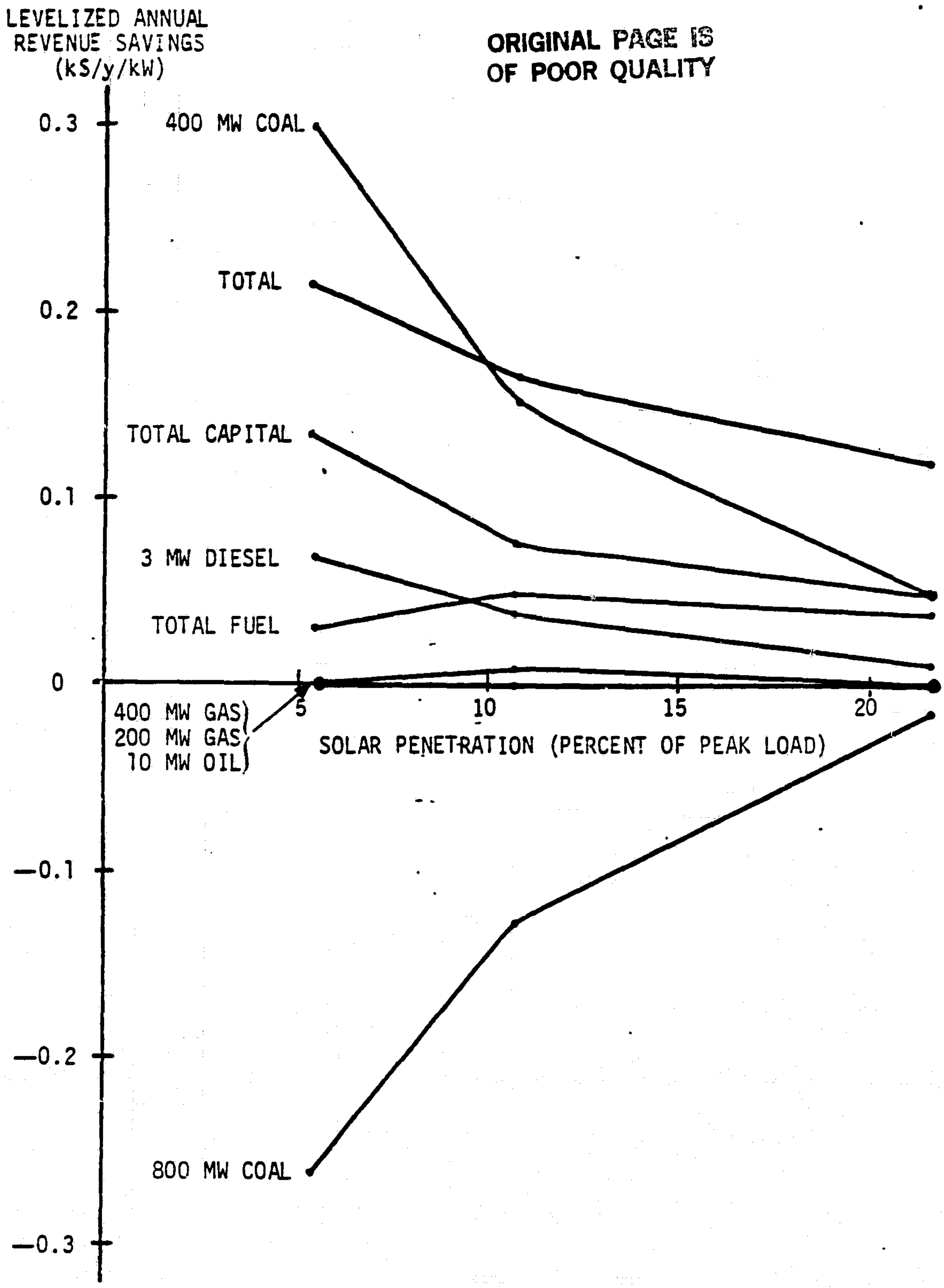

FIGURE 4-4. Solar System Savings—Municipal Utility
Rankine, No Storage, No Hybrid
Capital Cost Breakdown

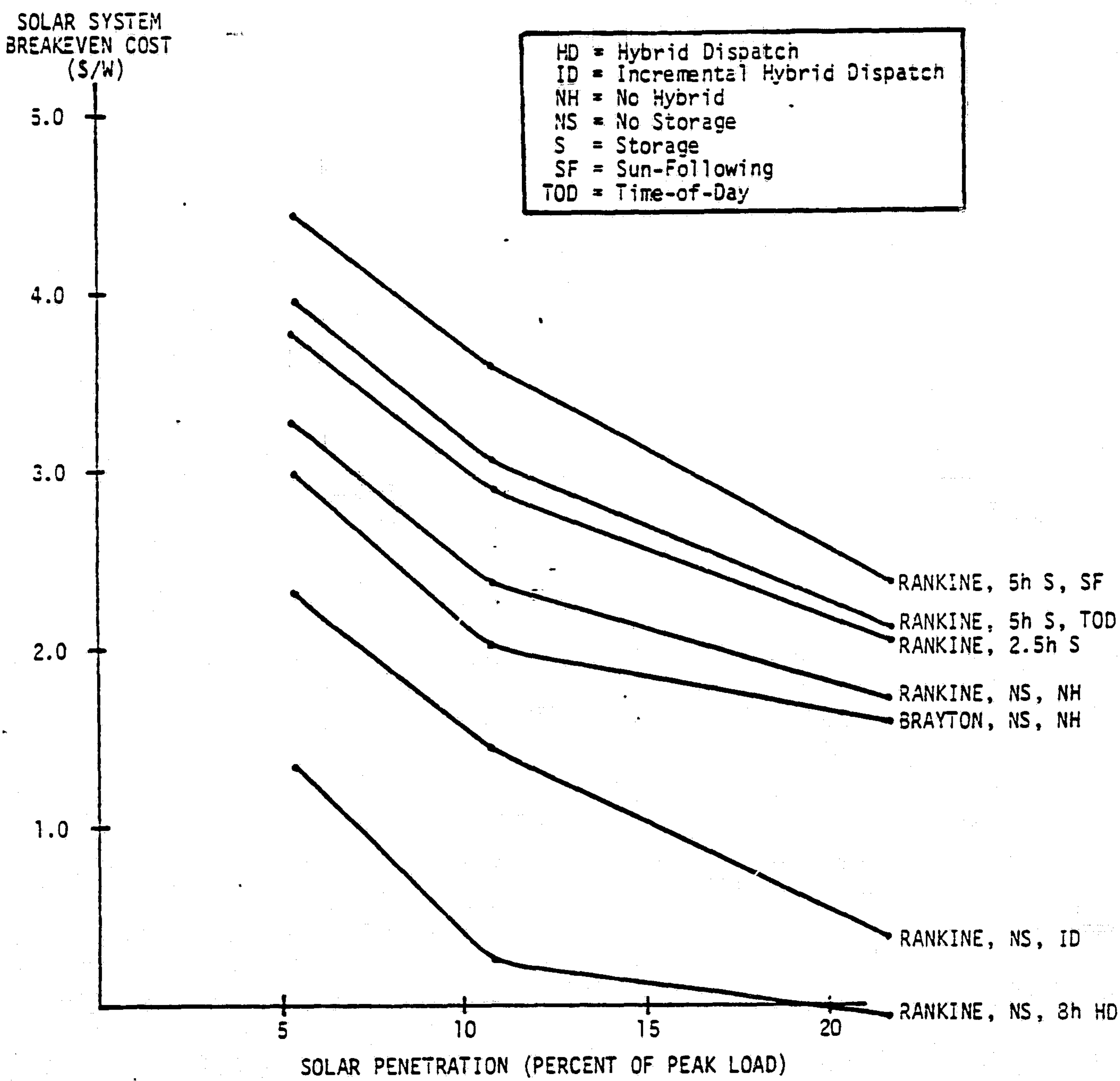

FIGURE 4-5. Solar System Breakeven Costs—Municipal Utility/Financing

The Brayton system value is lower because of poor part-load efficiency and hence lower annual capacity factor. Storage, of course, increases the annual capacity factor and hence yields a higher breakeven cost. It should be noted that the cost of storage includes both the cost of the storage subsystem itself and the cost for additional collector area per unit turbine size to achieve a higher solar multiple.

In all cases, the solar system breakeven cost decreases substantially as solar penetration level increases. Again, this is due to saturation of the marginal worth of solar generation as it begins to displace baseload capacity. This important effect indicates that solar system cost and performance improvements will continue to be necessary as solar penetration levels increase.

Solar breakeven costs for a variety of ownership alternatives are shown in Figures 4-6 and 4-7 for the Rankine no-storage and 5-hour storage configurations. Breakeven costs show a wide dispersion depending on the financing assumptions and investment criteria of the different users as described previously. For the Rankine no-storage configuration, for example, breakeven costs at 10 percent penetration range from a high of 2.37$/W for municipal ownership down to 0.44$/W for industry #6. Municipal financing is the most favorable, followed by federal installations, rural electric cooperatives, and the various industrial user criteria. Again, all breakeven costs decrease with penetration level.

4.6 SOLAR SYSTEM NET WORTH

A parametric analysis was performed to evaluate net solar system worth as a function of installed plant costs. Installed costs of 1,000$/kW, 1,200$/kW, 1,500$/kW, and 2,000$/kW were utilized in this analysis. Detailed cost estimates for the solar plant have not yet been developed for this study; however, current JPL goals for 1990 fall in the range 1,600-1,800$/kW. (see Table 3-7).

Figure 4-8 shows the net worth of the Rankine no-storage configuration as a function of penetration level for the various installed cost assumptions. At a low solar plant cost of 1,000$/kW, the optimum penetration level is near

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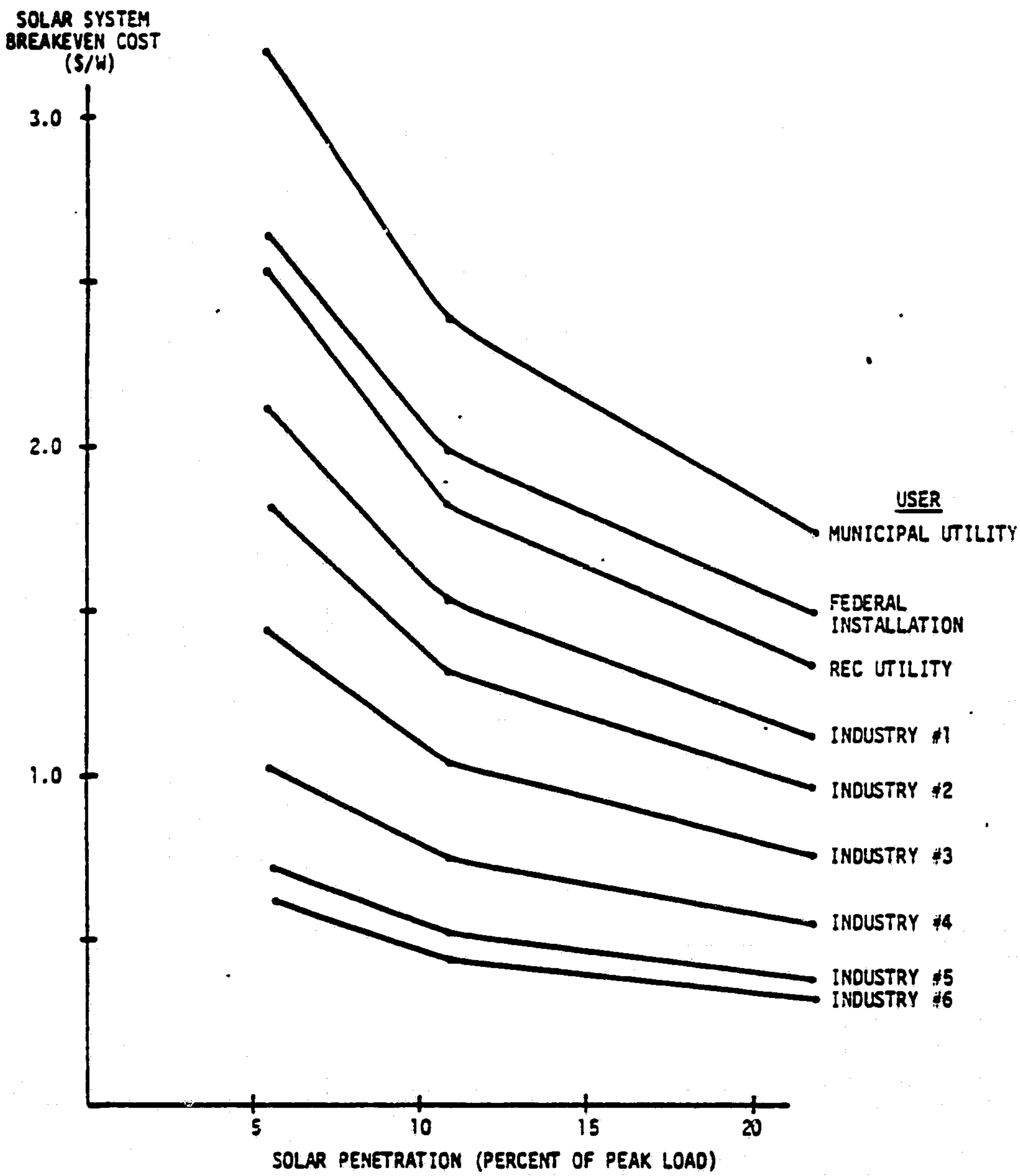

FIGURE 4-6. Solar System Breakeven Costs—Municipal Utility Rankine, No Storage, No Hybrid

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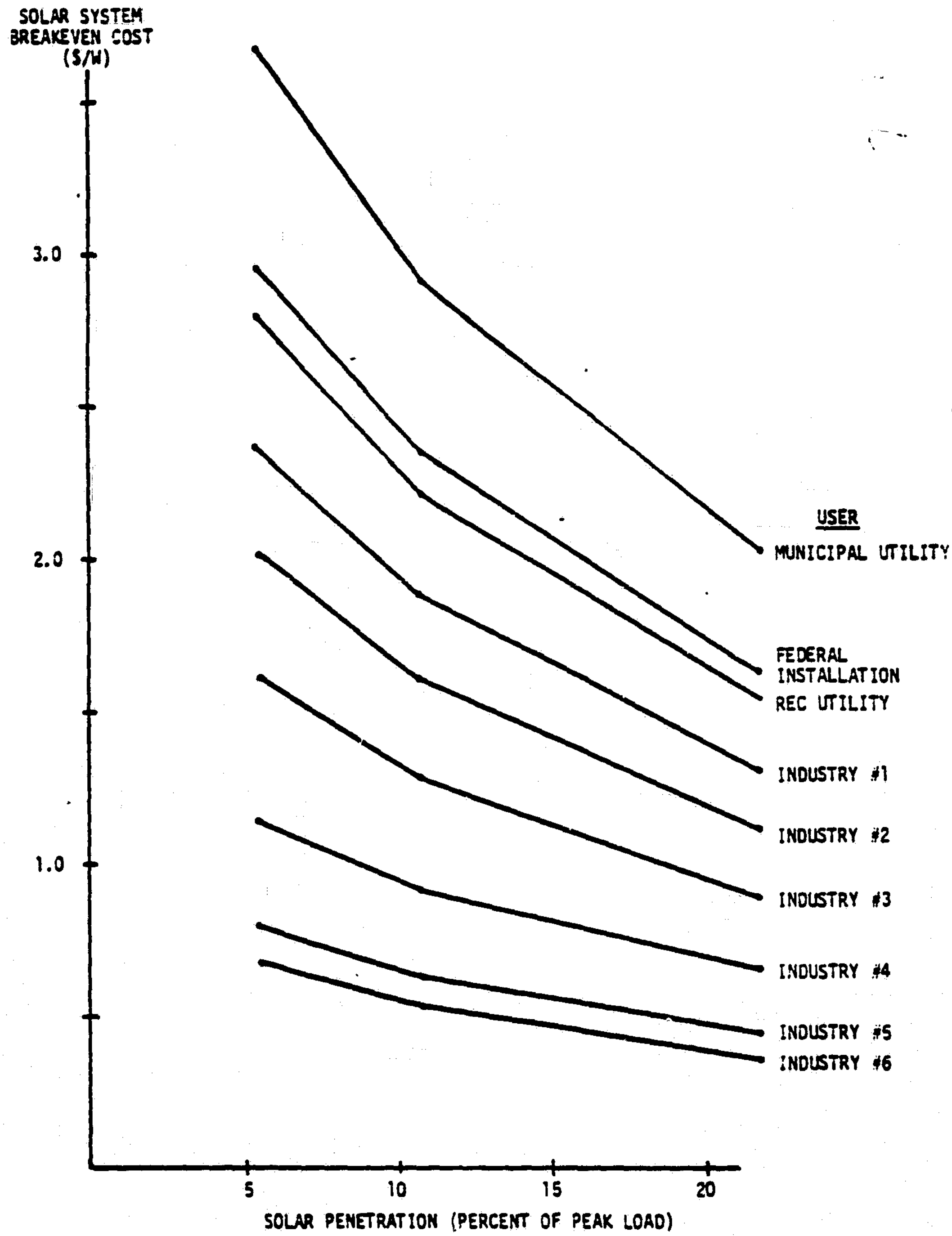

FIGURE 4-7. Solar System Breakeven Costs—Municipal Utility
Rankine, 5 Hour Storage, No Hybrid

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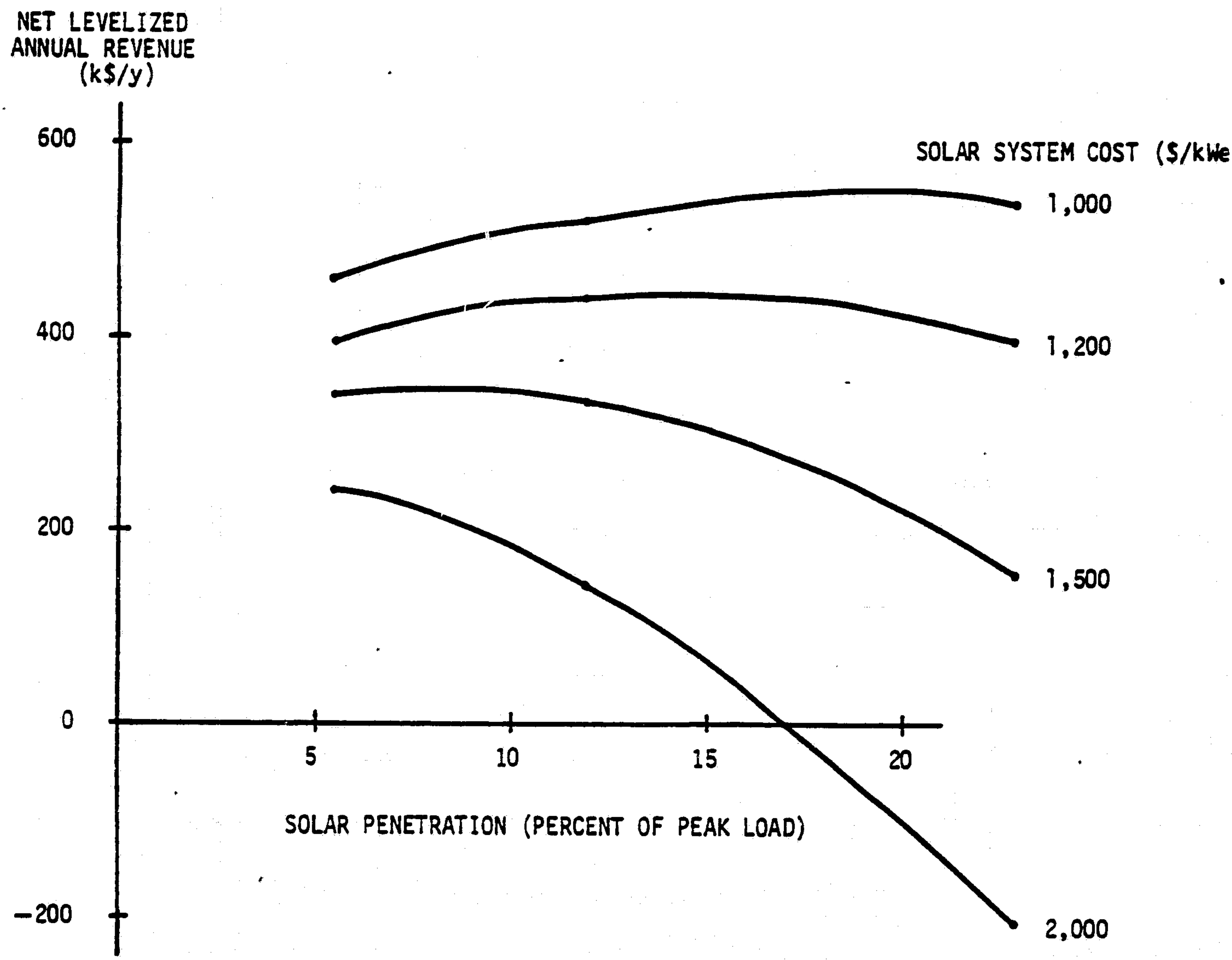

FIGURE 4-8. Solar System Net Worth—Municipal Utility
Rankine, No Storage, No Hybrid

15 percent; this decreases to 10 percent for 1,200$/kW, 5 percent for 1,500$/kW, and less than 5 percent for 2,000$/kW. The storage configuration permits higher penetration levels, although system cost would also increase considerably. Figure 4-9 shows net solar system value for the Rankine 5-hour storage configuration. At 2,000$/kW, for example, the 5-hour storage configuration has an optimum penetration level of about 10 percent.

Figure 4-10 shows net solar system worth for the hybrid configuration with incremental dispatch. Optimum penetration levels are quite low to prevent the hybrid fuels from displacing cheaper coal. Peak-shaving hybrid dispatch will be investigated in future analyses.

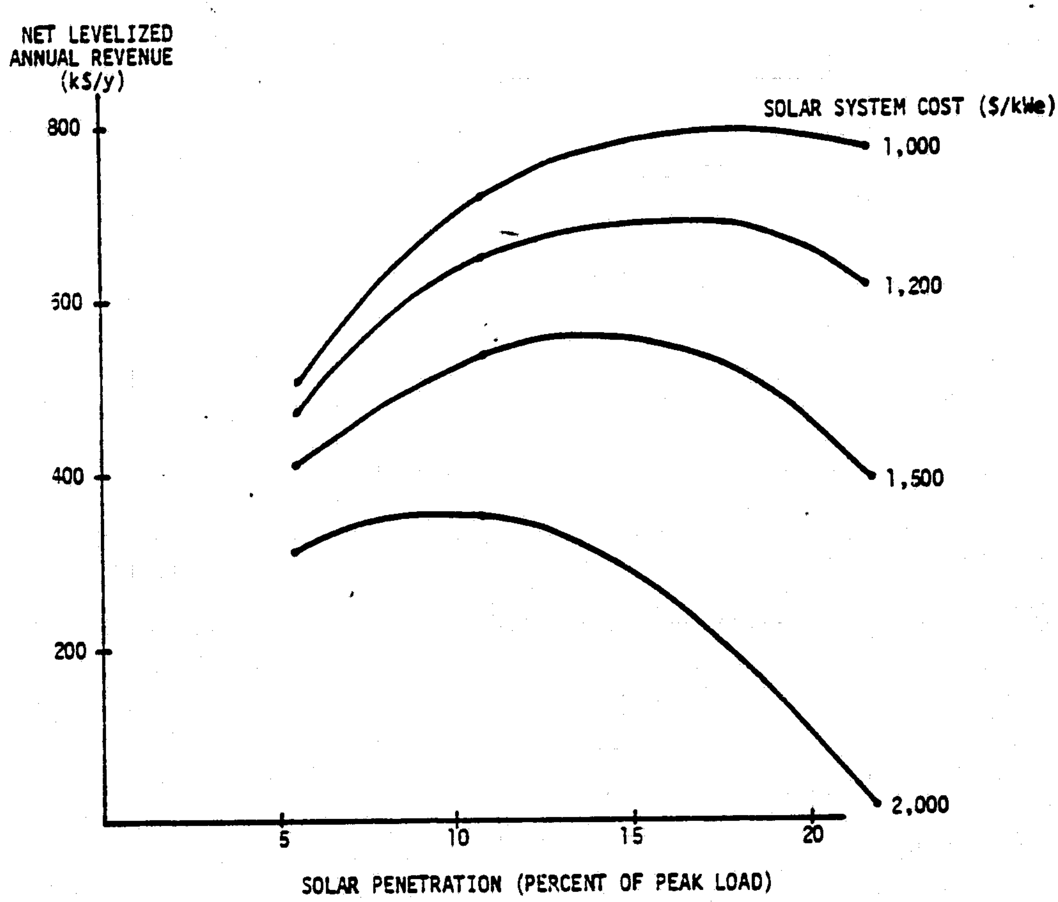

FIGURE 4-9. Solar System Net Worth—Municipal Utility
Rankine, 2.5 Hour Storage, No Hybrid

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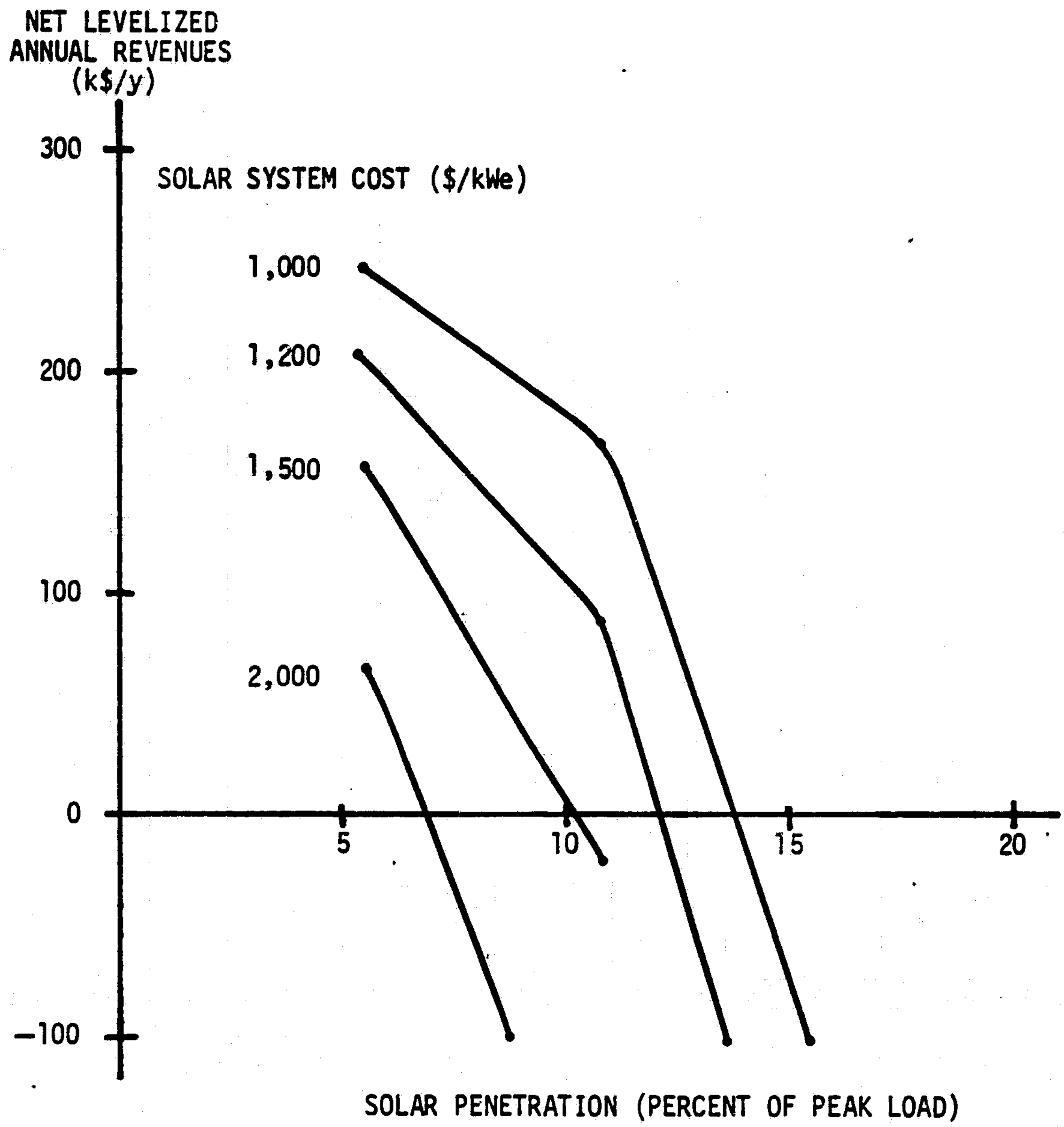

FIGURE 4-10. Solar System Net Worth—Municipal Utility
Rankine, No Storage, Incremental Hybrid Dispatch

4.7 SOLAR SYSTEM WORTH SENSITIVITY TO NUCLEAR EXPANSION

To study the effects of nuclear plant expansion on the revenue savings resulting from use of the solar system, the municipal utility was allowed to share a fraction of a large nuclear plant in the capacity expansion. For the assumed nuclear capacity costs, a large portion of the 1990 total installed system capacity results in nuclear. Intermediate and peaking units are primarily run only during periods when the nuclear plant is on maintenance. As a result, the introduction of solar generation displaces a significant amount of nuclear baseload. Thus, the solar system breakeven costs are significantly reduced (for example, by more than 1$/W for the Rankine, 2.5 hour storage, no hybrid case). Using solar to displace a significant fraction of baseload capacity is generally not a cost effective use of solar generation. For this reason, nuclear plant expansion was removed from further consideration in the municipal case.

SECTION 5

INVESTOR-OWNED UTILITY RESULTS

SECTION 5

INVESTOR-OWNED UTILITY

This section describes selected impacts analysis results for the large investor-owned utility case studies. Both hybrid and storage solar plant configurations were evaluated using Phoenix meteorological data.

5.1 SOLAR SYSTEM SAVINGS

Total savings of fixed and variable conventional generation costs are summarized in Figure 5-1 for the various system configurations. Savings are expressed as total levelized annual revenue savings to the utility per unit kW of solar generation.

The savings per solar plant are significantly lower for the large investor-owned utility than for the small municipal. Both the capacity savings and fuel savings are reduced because the large utility has considerably larger generator units with lower fixed and variable costs. For example, the 50 MW combustion turbine peaking unit has a capital cost of 185 $/kW, a heat rate of 14 Btu/MWh, and uses distillate oil. In contrast, the 3MW high speed diesel unit for the municipal has a much higher capital cost of 357 $/kW, a slightly higher heat rate of 10.6 MBtu/MWh, and uses more expensive diesel fuel. Thus, the savings per plant are lower even though the insolation of Phoenix is considerably higher, yielding a higher solar plant capacity factor. For comparison, an additional analysis is shown in Figure 5-1 for a Rankine system in Fort Worth, Texas.

As in the municipal case study, the savings per solar kW for the investor-owned utility decreases at higher penetration levels. However, the rate of decrease is somewhat less because the large utility has a broader mix of conventional generation which can better accomodate the increased solar generation.

The value of the solar system increases as storage is added because of the higher solar plant capacity factor. The addition of hybrid

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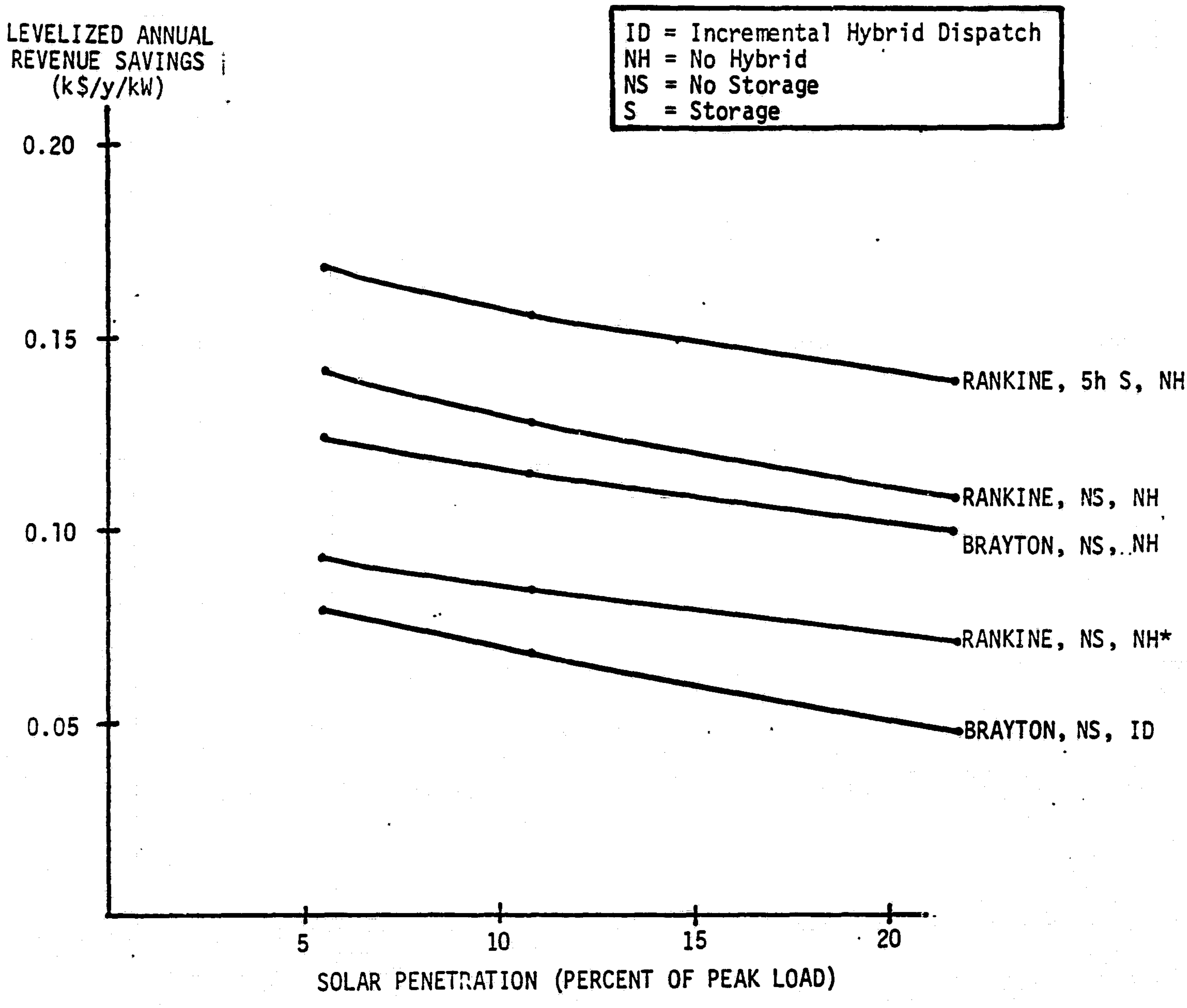

*Fort Worth Site Sensitivity.

FIGURE 5-1. Solar System Savings—Investor-Owned Utility

also increases the revenue savings, but after subtracting the cost of hybrid fuel (as is done in Figure 5-1) the net savings are substantially less than the no-hybrid case for incremental hybrid dispatch. The results are even worse for the 8-hour and 24-hour hybrid dispatch. This is because expensive oil is being used to displace efficient gas generation and inexpensive coal fuels. It is expected that peak-shaving dispatch which varies with the instantaneous value of the utility load will considerably improve the hybrid results; this will be investigated in future analyses.

5.2 CAPACITY IMPACTS

Capacity impacts for the various solar plant configurations are summarized in Table 5-1. For the non-storage systems, essentially combustion turbine capacity only is displaced up to the 20% penetration level, at which point some intermediate coal capacity is also displaced. By contrast, with the 5 hour storage configuration intermediate coal capacity is displaced at all penetration levels with an opposite increase in combustion turbine capacity.

Total MW capacity displaced per unit MW solar capacity is shown in Figure 5-2. As expected, the total capacity displacement decreases with penetration level and is lower for the Brayton cycle than for the Rankine and is also lower for the Fort Worth site. It is interesting that the Rankine 5 hour storage configuration displaces significantly less total capacity than the no-storage configuration. This emphasizes the fact that the type of capacity displaced is very important in understanding the capacity value of solar generation. For the storage configuration, solar is displacing a significant amoung of high-cost, capital intensive coal capacity while actually adding low-cost combustion turbine capacity. The net capacity displacement is less than the no-storage configuration, but the value is quite different because low-cost peaking capacity only is being displaced in the no-storage case. Similarly, the capacity impacts must also be evaluated in conjunction with the fuel impacts. For example, the 5 hour storage configuration displaces primarily coal and gas with very little impact on oil consumption.

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TABLE 5-1. Solar Capacity Displacement
Investor-Owned Utility

SOLAR PLANT	SOLAR PENETRATION (% PEAK LOAD)	CAPACITY DISPLACED		
		50 MW COMBUSTION TURBINE	400 MW COAL	TOTAL (MW)
BRAYTON No Storage No Hybrid	5.4	305.44	-0.12	305.32
	10.9	454.86	0.01	454.87
	21.7	226.96	146.08	373.04
RANKINE No Storage No Hybrid (Fort Worth Sensitivity)	5.4	160.93	-0.12	160.81
	10.9	212.05	-0.20	211.85
	21.7	-24.19	58.6	34.42
RANKINE No Storage No Hybrid	5.4	350.36	-0.20	350.16
	10.9	503.86	-0.20	503.66
	21.7	259.76	146.44	406.2
RANKINE 5 Hours Storage No Hybrid	5.4	-189.05	475.16	288.11
	10.9	-278.75	479.28	200.52
	21.7	-499.78	478.96	-20.83
RANKINE No Storage Incremental Hybrid Dispatch	5.4	346.68	-0.20	346.48
	10.9	513.86	1.16	515.00
	21.7	212.76	146.08	358.83

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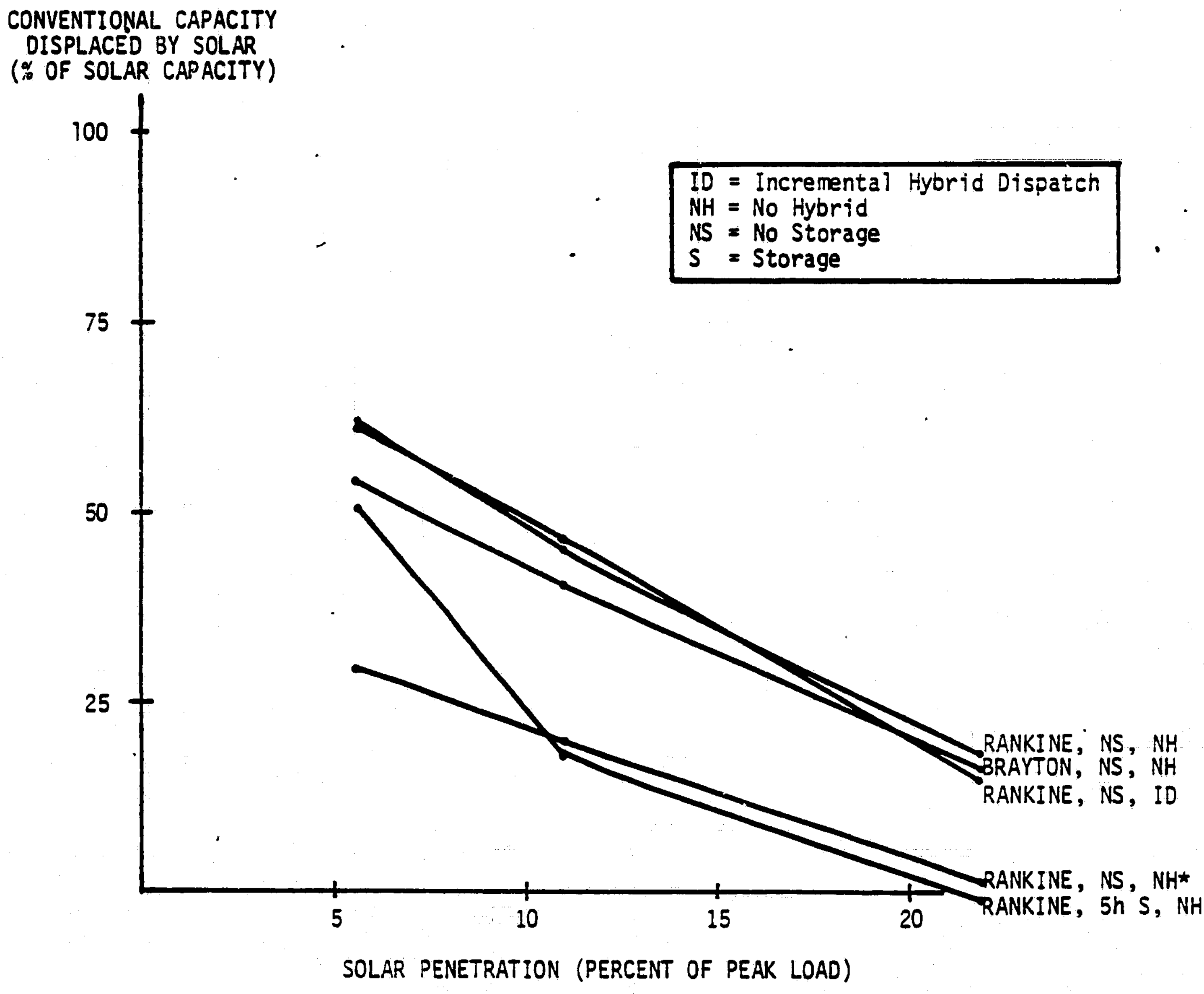

*Fort Worth Site Sensitivity.

FIGURE 5-2. Solar Capacity Credit—Investor-Owned Utility

5.3 FUEL SAVINGS

Fuel savings resulting from solar generation are summarized in Figures 5-3 and 5-4 for the Rankine configurations without and with storage, respectively. Other configurations display similar characteristics to the no-storage configuration. Capital, O&M, and total cost savings are also shown.

For the large investor-owned utility, fuel savings represent the primary value of the solar generation. Captial cost and O&M savings are generally small by comparison. Thus, the solar capacity acts primarily as a fuel saver.

For the no storage configuration, the primary fuel savings is natural gas. At higher penetration levels, the natural gas displacement per solar kW decreases somewhat and coal savings increase.

When storage is added, the optimum capacity mix changes significantly as discussed previously. At 5% penetration, coal is the primary fuel savings and natural gas consumption is actually increased. Moreover, capital cost savings are significant because expensive coal capacity is replaced by low-cost combustion turbines. At the higher penetration levels, gas and coal fuel displacement are significant with reduced capital cost savings per solar kW.

5.4 CAPITAL COST SAVINGS

Capital cost savings for the configurations without storage are quite small relative to fuel savings and consist primarily of low-cost combustion turbine peaking capacity, with some coal displacement at 20% penetration. The 5 hour storage configuration, as discussed previously, did provide significant capacity savings by displacing high-cost intermediate coal capacity. Figure 5-5 provides a capital cost breakdown for the Rankine 5 hour storage configuration at various penetration levels.

Coal capacity savings are high per unit kW of solar particularly at the 5% penetration level, followed by rapid decrease at higher penetration levels. Combustion turbine capacity is actually added at all three

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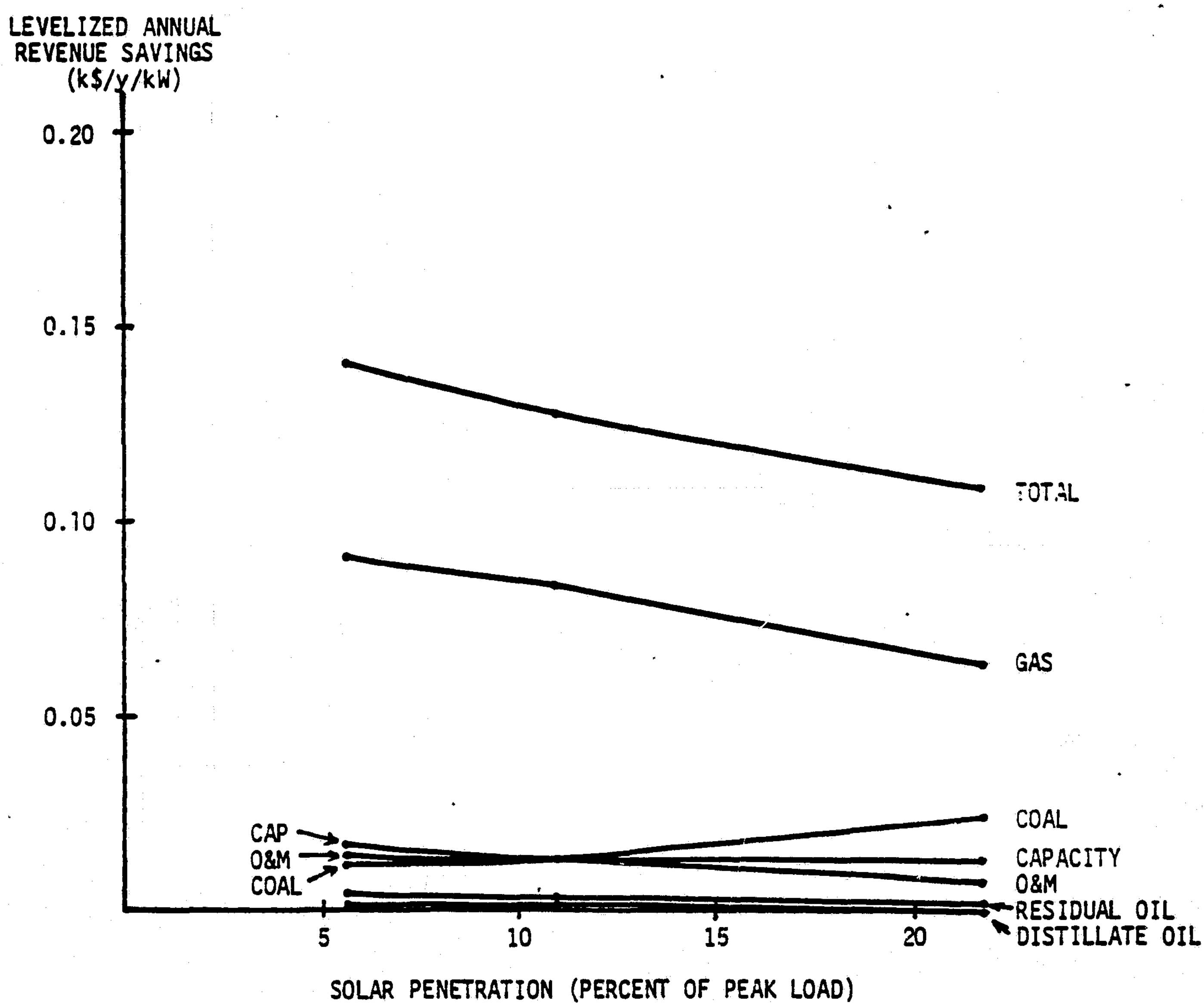

FIGURE 5-3. Solar System Savings—Investor-Owned Utility
Rankine, No Storage, No Hybrid
Fuel Cost Breakdown

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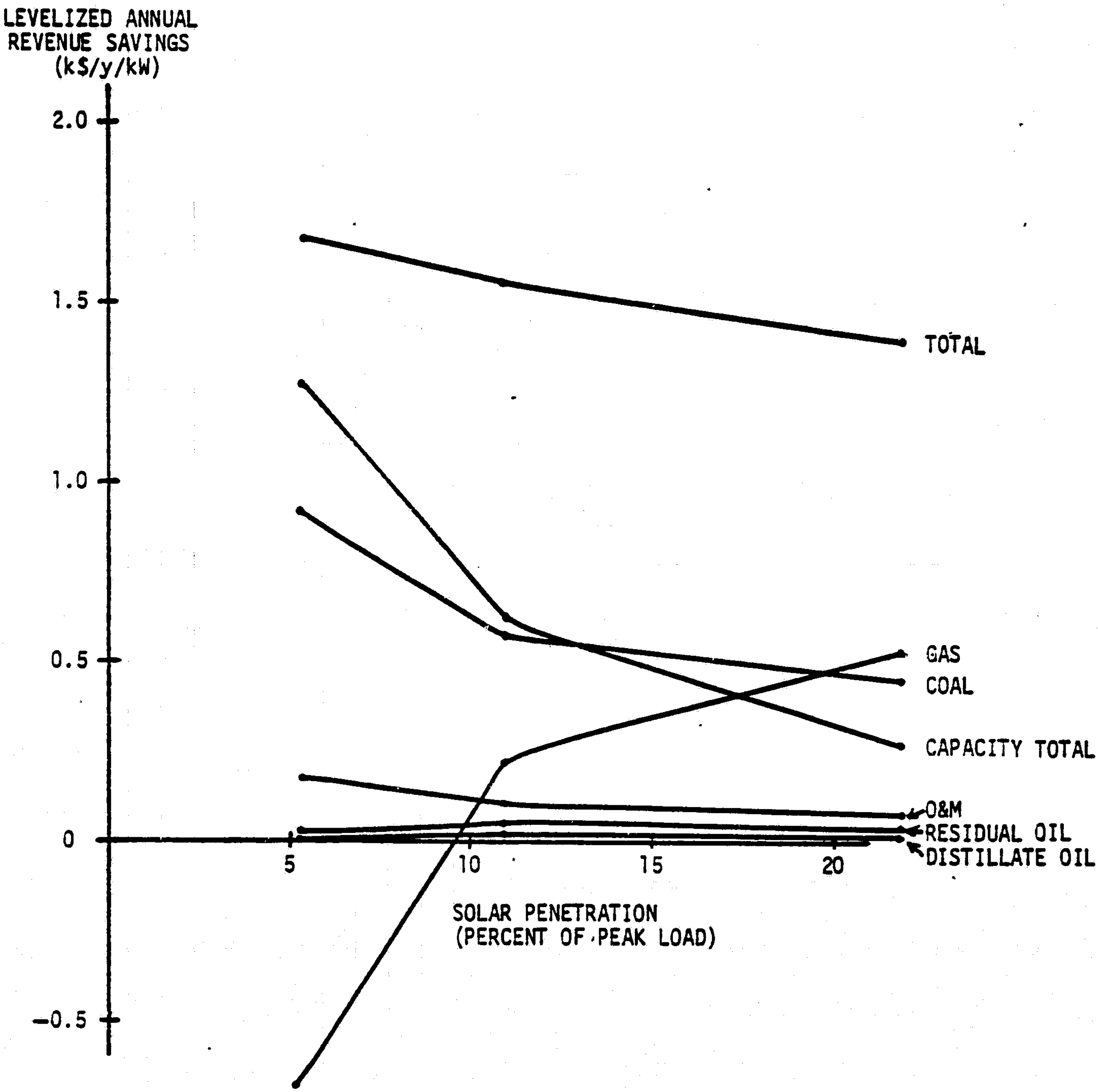

FIGURE 5-4 Solar System Savings—Investor-Owned Utility
Rankine, 5 Hour Storage, No Hybrid
Fuel Cost Breakdown

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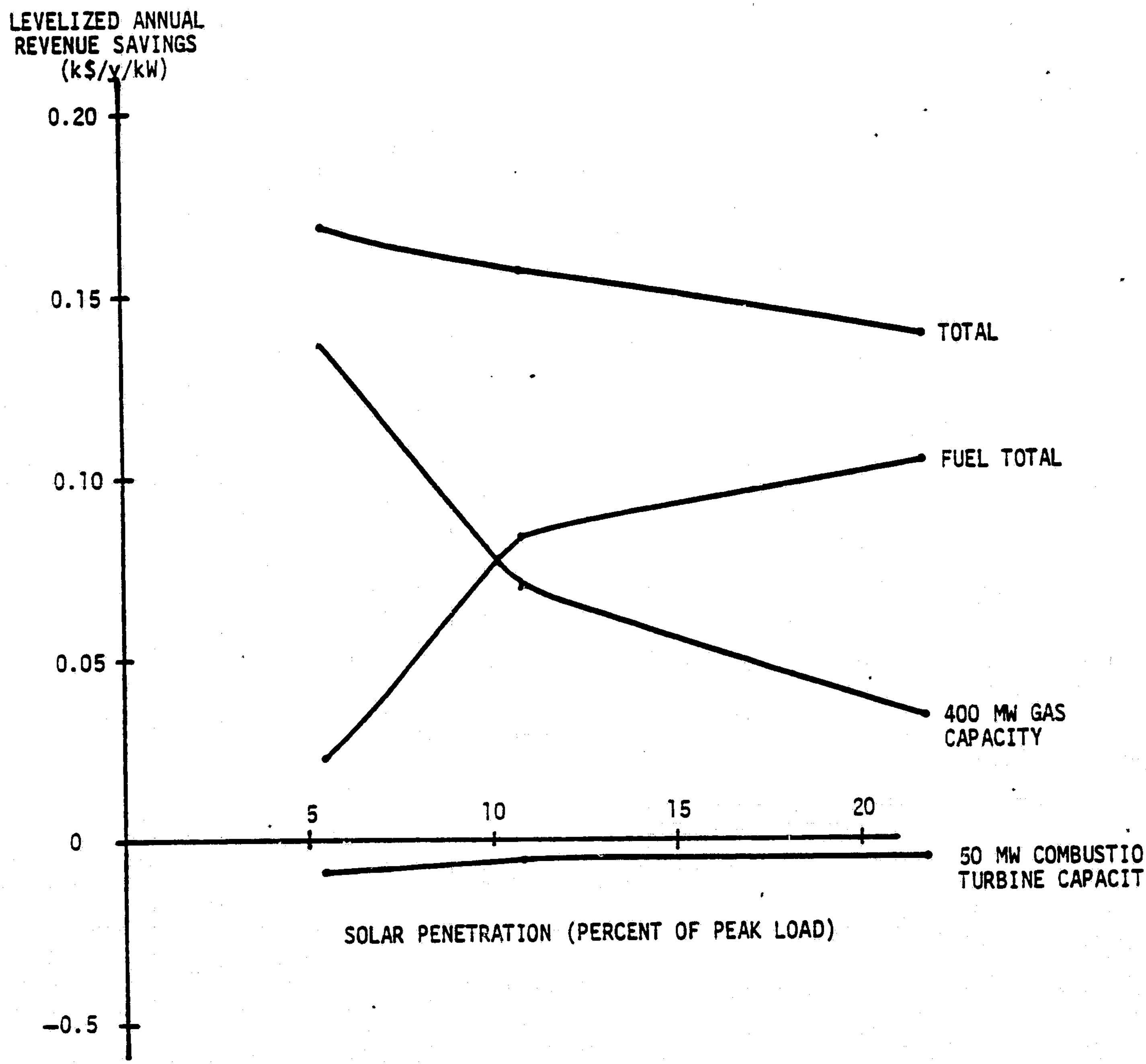

FIGURE 5-5. Solar System Savings—Investor-Owned Utility
Rankine, 5 Hour Storage, No Hybrid
Capacity Cost Breakdown

solar penetration levels.

5.5 SOLAR SYSTEM BREAKEVEN COSTS

Solar system breakeven costs are computed assuming that the utility savings are passed on to the solar plant owner. Figure 5-6 summarizes the solar plant breakeven costs for the case of ownership by the investor-owned utility itself. As in the municipal utility case, breakeven solar system costs decrease with increasing solar penetration. In general, the breakeven costs for the investor-owned utility are significantly lower than for the municipal. This is because of reduced solar system revenue savings as discussed previously, the tax deductibility of fuel and operating expenses, and more expensive equity financing for the solar plant.

The highest breakeven cost occurs for the Rankine 5 hour storage configuration. However, the costs for storage and additional collector area (required to yield a solar multiple of 2.0) are probably not justified by the small 300-400 $/kW gain in breakeven costs, since collector costs are very expensive. This issue will be investigated further in subsequent analyses.

The Rankine configuration without storage and hybrid has breakeven costs in the range 1200-1500 $/kW. The Brayton cycle has somewhat lower breakeven costs because of the lower capacity factor. The Rankine system with incremental hybrid dispatch shows a net loss breakeven cost because expensive hybrid residual oil is being used to displace inexpensive coal and efficient gas fuels. At higher penetration, the hybrid configuration performs particularly poorly as more coal is being displaced by hybrid oil consumption. These results indicate the need to dispatch hybrid more selectively as a peaking unit; peak shaving dispatch will be investigated in subsequent analyses. Breakeven costs are lowest for the Rankine system in Fort Worth, where insolation is not as high as in Phoenix.

Solar breakeven costs for a variety of ownership alternatives are shown in Figures 5-7 and 5-8 for the Rankine systems without and with storage. Breakeven costs again show a wide dispersion depending on the

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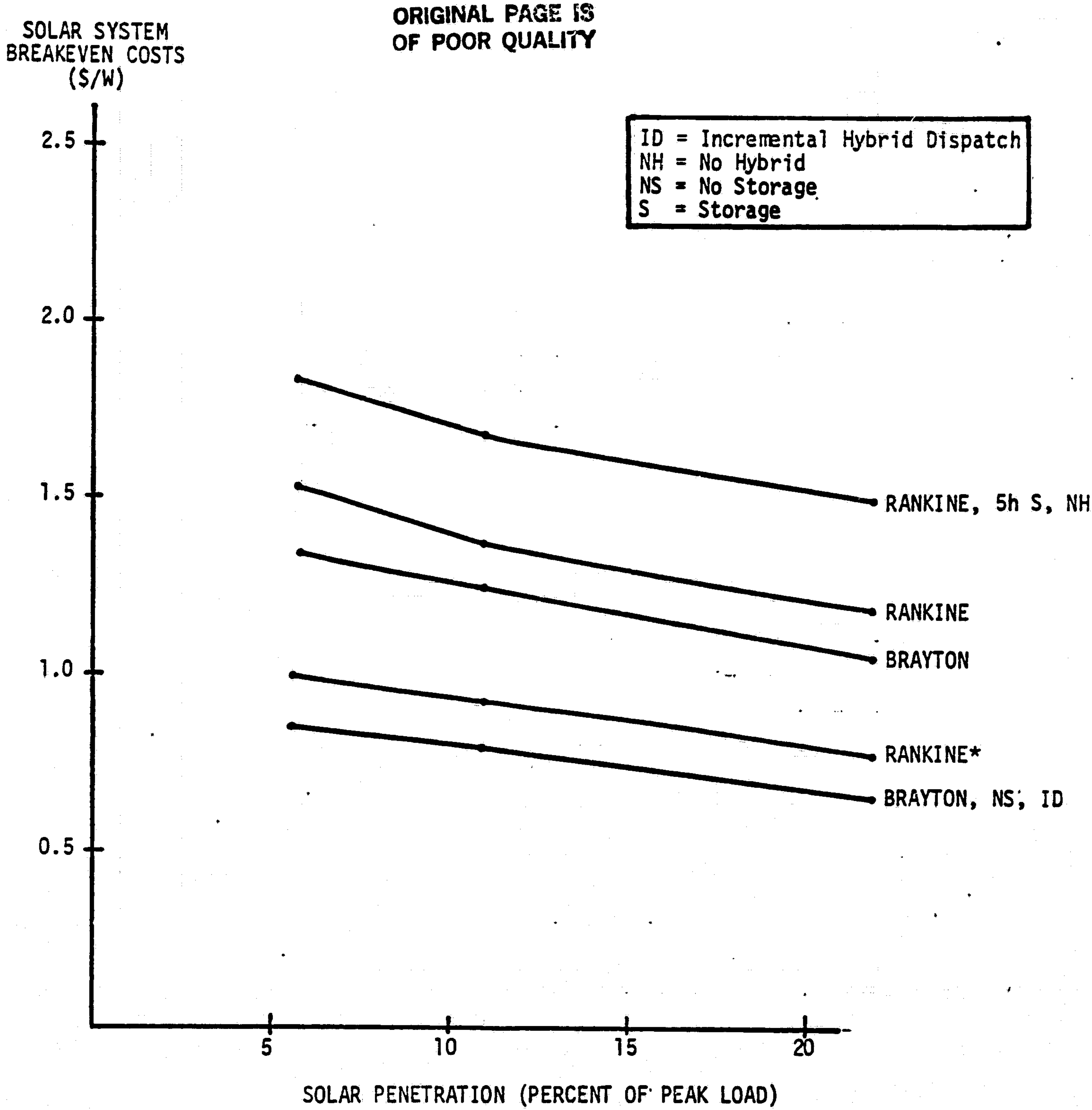

*Fort Worth Site Sensitivity.

FIGURE 5-6. Solar System Breakeven Costs—Investor-Owned Utility/Financing

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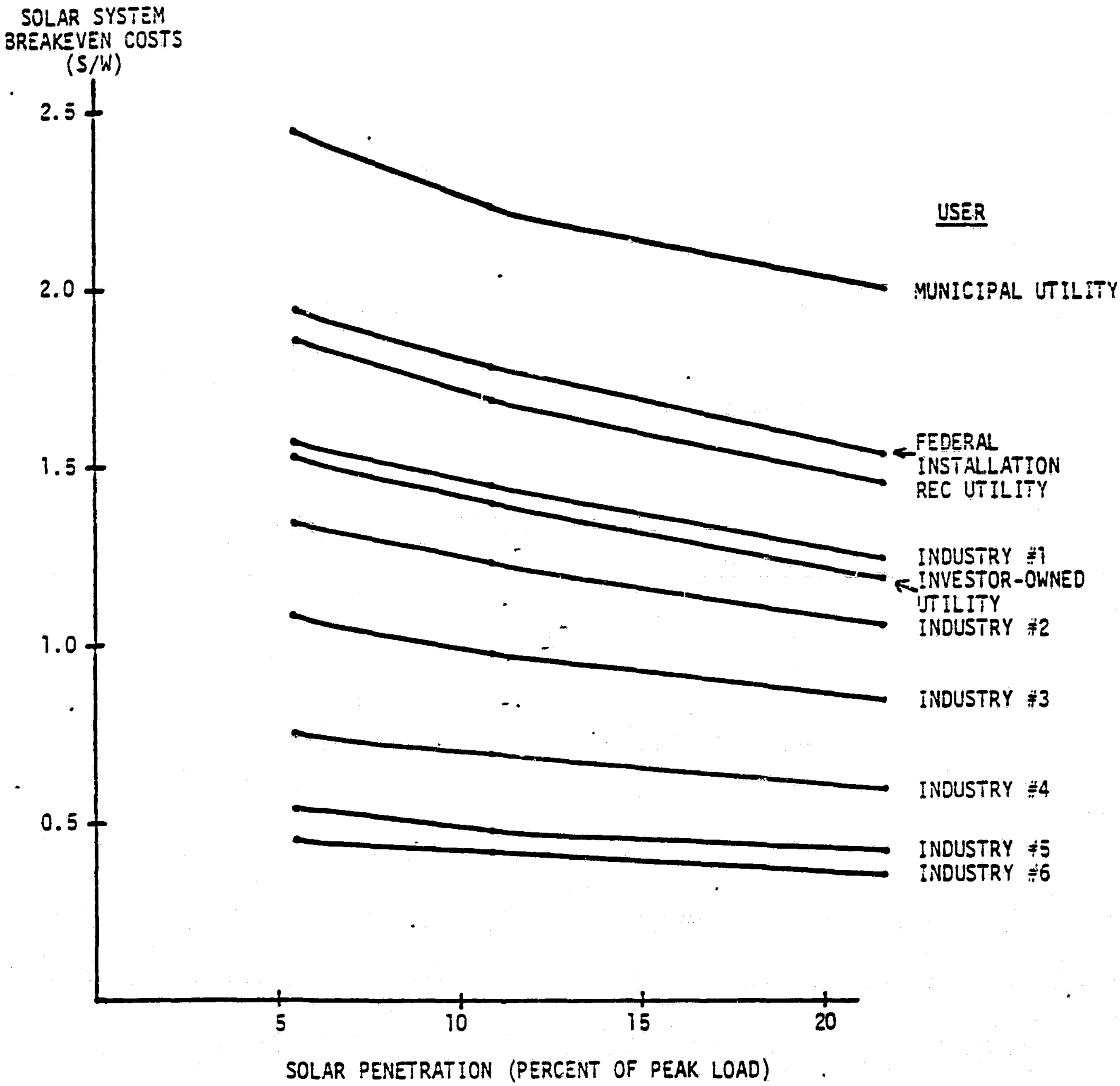

FIGURE 5-7. Solar System Breakeven Costs—Investor-Owned Utility
Rankine, No Storage, No Hybrid

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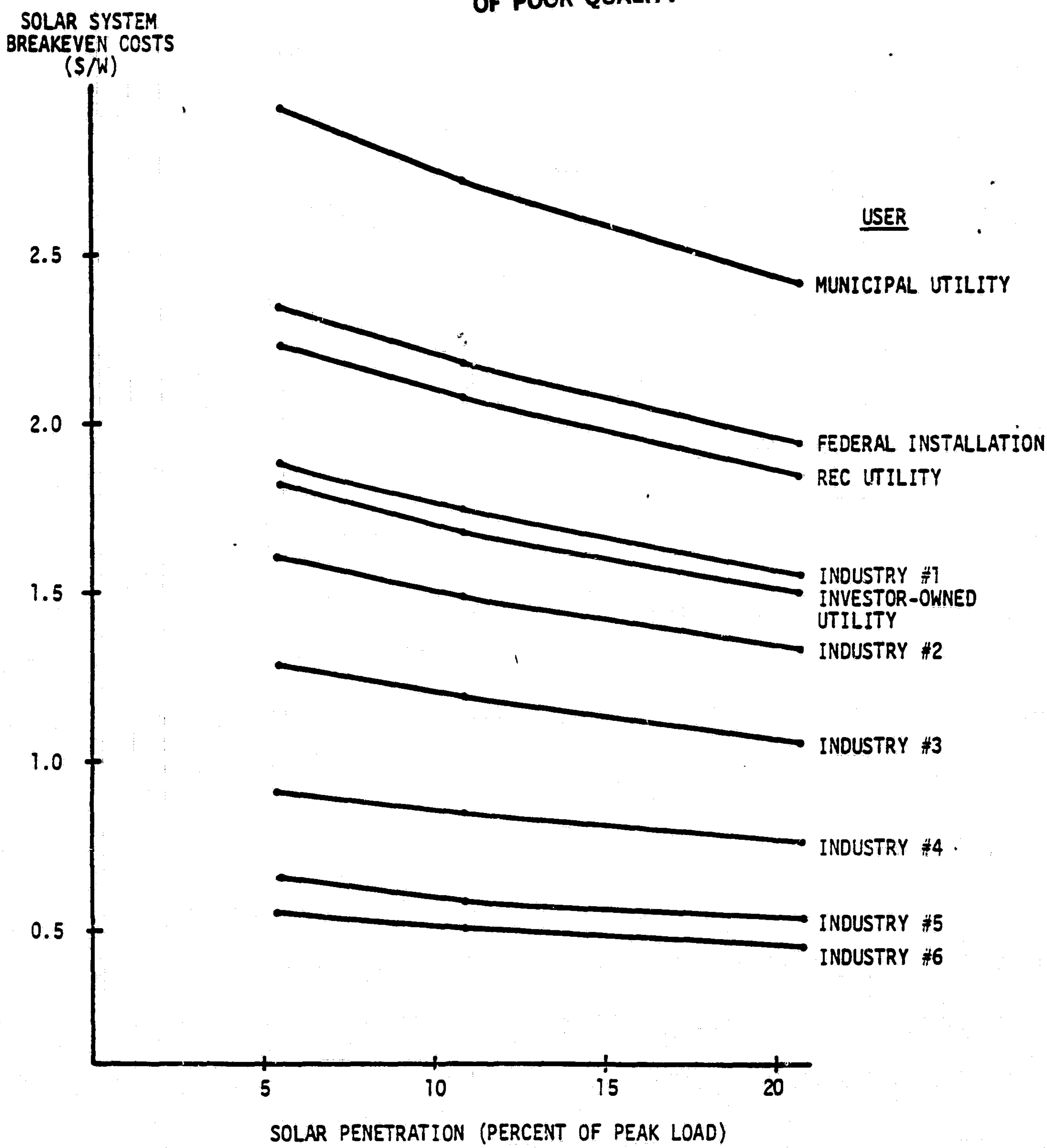

FIGURE 5-8. Solar System Breakeven Costs—Investor-Owned Utility
Rankine, 5 Hour Storage, No Hybrid

financing assumptions and investment criteria of the different users. For the Rankine no-storage configuration at 10% penetration, for example, breakeven costs range from a high of 2450 $/kW for municipal financing down to 450 $/kW for industry #6. The most favorable case is a municipal utility which purchases power from the large investor-owned utility and chooses to finance a solar power plant. Other favorable owners include government and rural electric cooperatives, followed by industry #1 and the investor-owned utility itself. Figure 5-9 shows breakeven costs for the various system configurations for the most favorable municipal financing case. The basic features are of course quite similar to Figure 5-6.

The methodology automatically performs a sensitivity analysis with respect to solar plant O&M, tax credit, and property tax and insurance for each ownership alternative. Table 5-2 shows solar system breakeven costs for several values of these parameters at the 5% penetration level for ownership by the large utility. The tax credit in particular has a large impact on solar system breakeven cost.

5.6 SOLAR SYSTEM NET WORTH

A parametric analysis was performed to evaluate net solar system worth as a function of installed system costs. The results are shown in Figure 5-10 for the no-storage Rankine configuration and Figure 5-11 for the 5 hour storage configuration. Even though breakeven costs are lower for the investor-owned utility, optimum penetration levels are comparable to the municipal. This is because the large utility has a broad generation mix with more flexibility to adjust to solar generation. For the no-storage configuration, optimum penetration levels are in the range of 10 to 20 percent for system cost values in the range of 1,000-2,000 $/kW. For the storage configuration, optimum penetration levels are somewhat greater at the same system cost; of course, the storage configuration actually has a considerably higher installed system cost.

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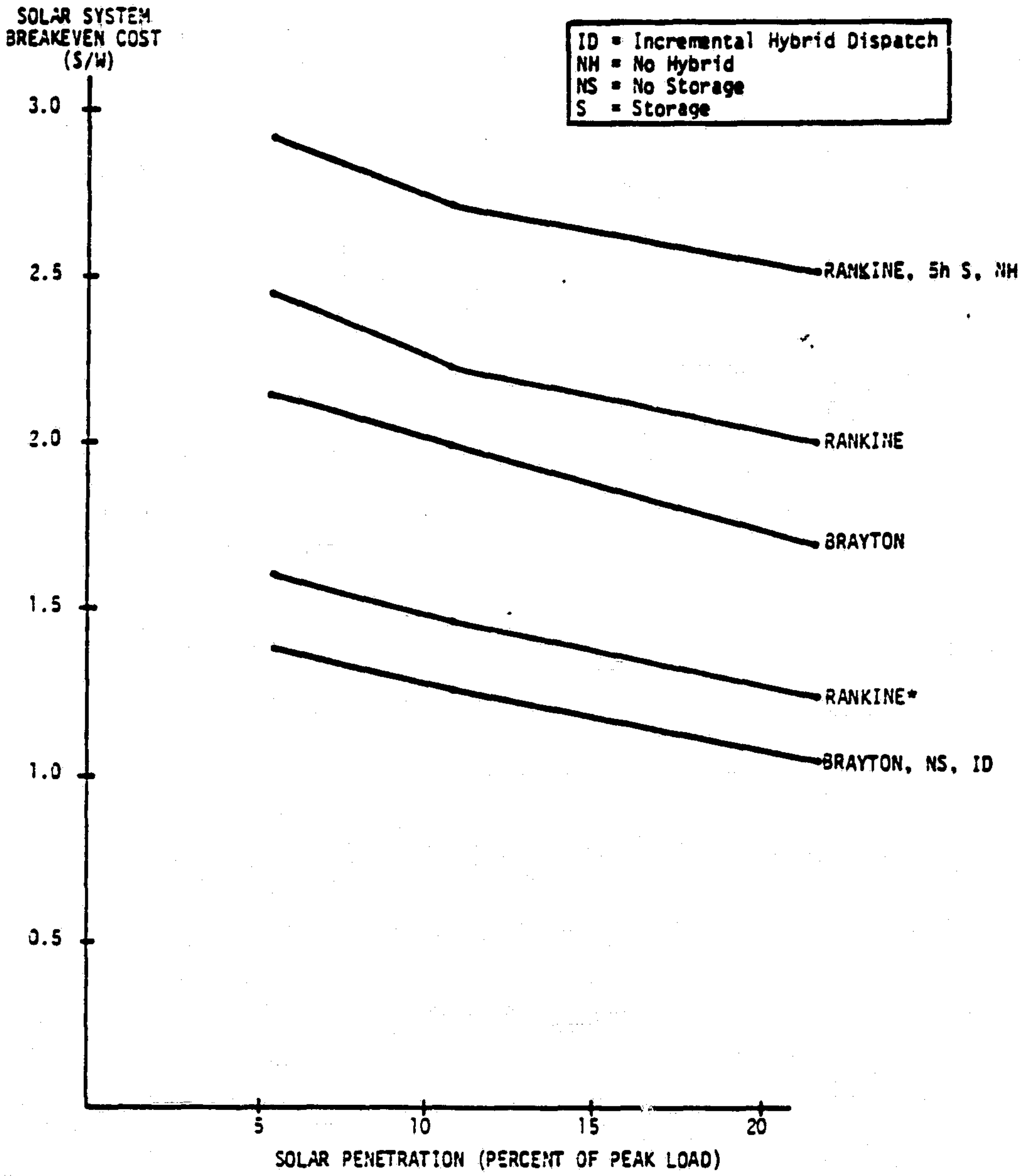

*Fort Worth Site Sensitivity.

FIGURE 5-9. Solar System Breakeven Costs—Investor-Owned Utility Municipal Financing

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TABLE 5-2. Solar System Breakeven Costs
Economic Sensitivity Analysis

Rankine, No Storage, No Hybrid
5.4 Percent Penetration
0.50 Tax Rate
0.10 Cost of Capital
Investor-Owned Utility Financing

O&M RATE	TAX CREDIT	PROPERTY TAX AND INSURANCE	SOLAR SYSTEM BREAKEVEN COSTS ($/W)	
0.0131	0.100	0.0025	1.421	
		0.0125	1.291	
	0.300	0.0025	1.838	
		0.0125	1.626	
0.0065	0.100	0.0025	1.521	◀BASELINE
		0.0125	1.373	
	0.300	0.0025	2.010	
		0.0125	1.759	

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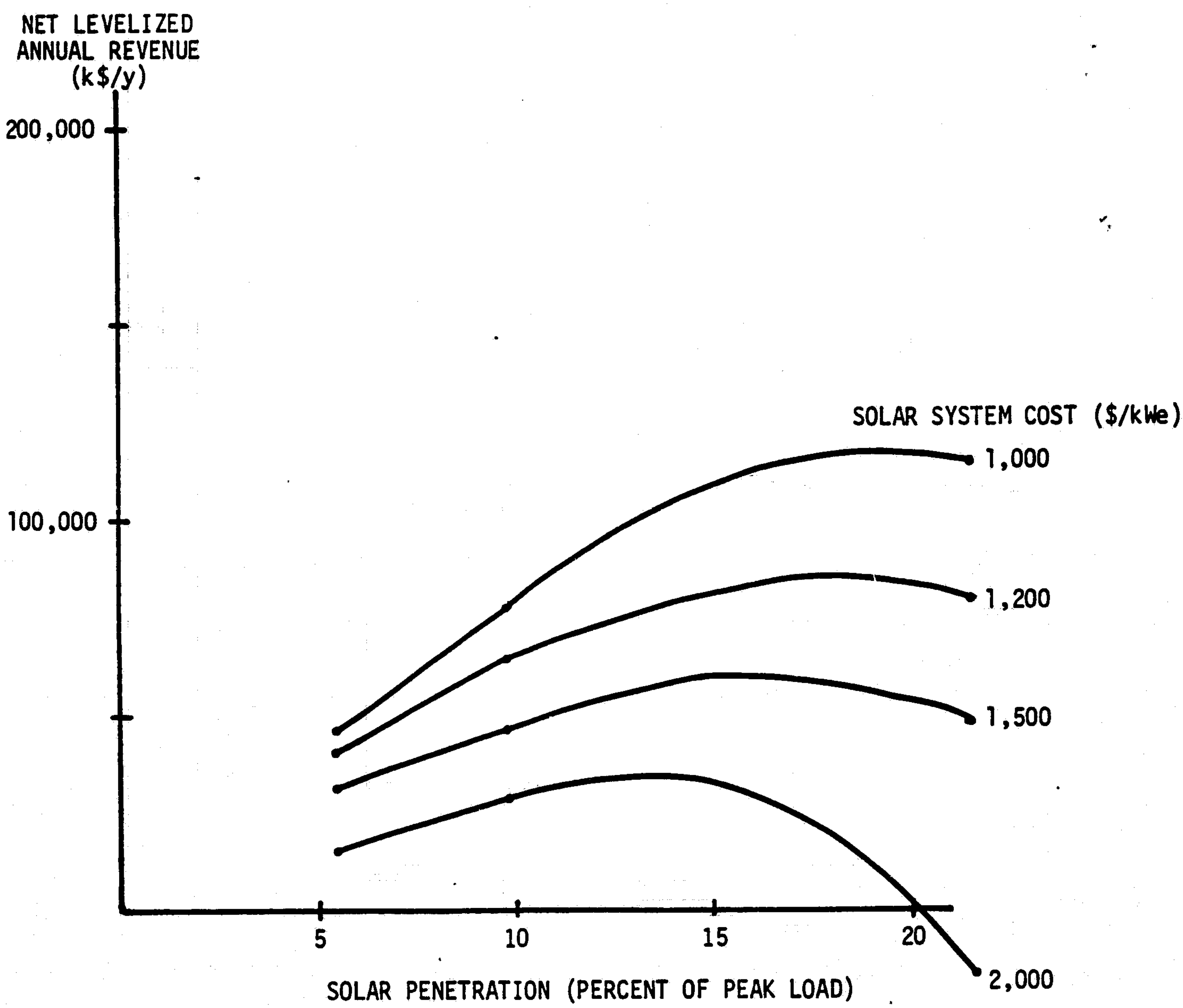

FIGURE 5-10. Solar System Net Worth—Investor-Owned Utility
Rankine, No Storage, No Hybrid

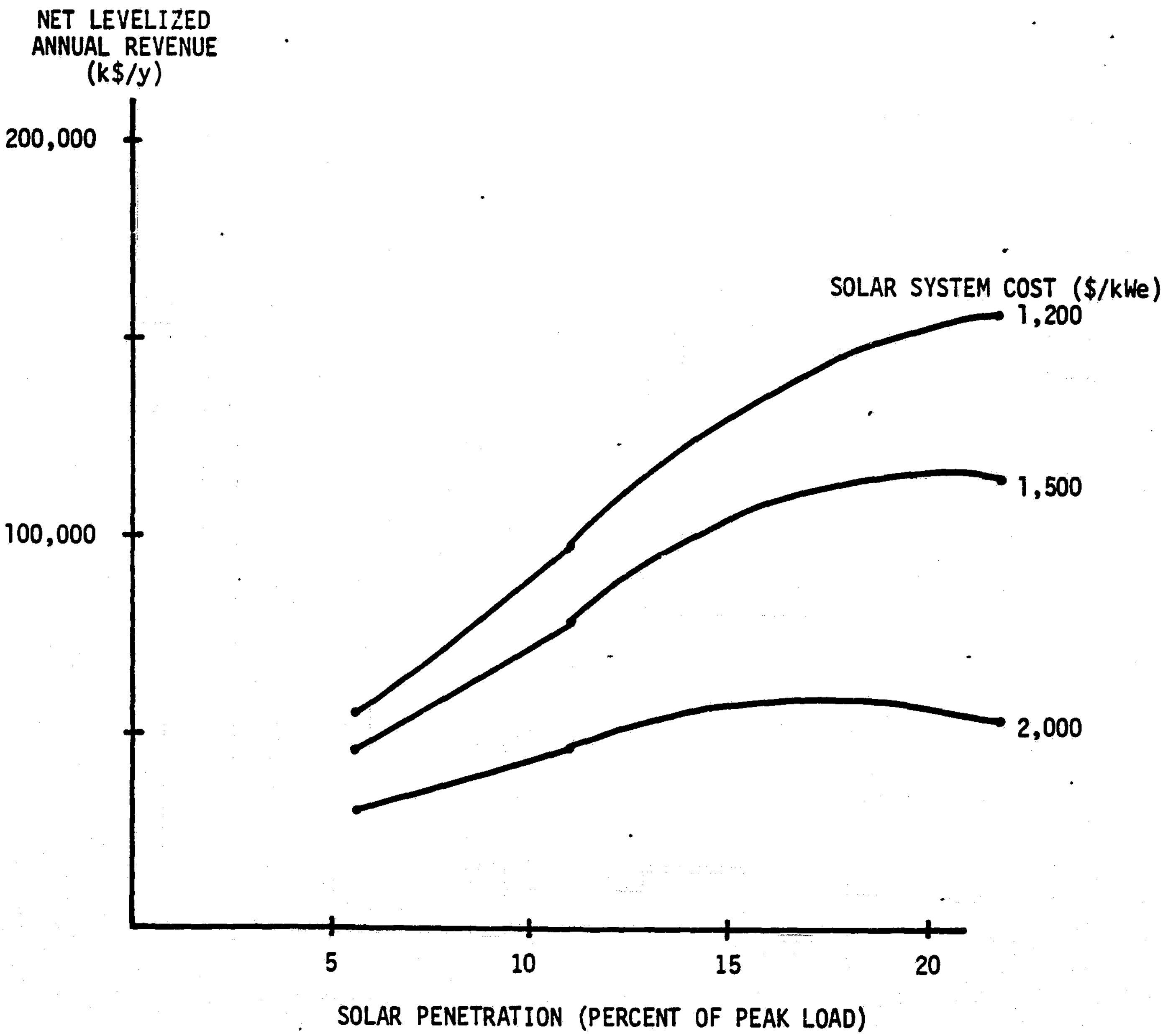

FIGURE 5-11. Solar System Net Worth—Investor-Owned Utility
Rankine, 5 Hour Storage, No Hybrid

SECTION 6

ISOLATED GOVERNMENT UTILITY RESULTS

SECTION 6

ISOLATED GOVERNMENT UTILITY RESULTS

This section summarizes impacts analysis results for the isolated government utility case study. The open Brayton turbine cycle was evaluated with and without hybrid using Phoenix meterological data. Because the government utility is assumed to be isolated from the grid, it is not permitted to purchase power or share fractions of a large, efficient plant with other utilities. For this reason, the baseline expansion through 1990 selects only diesel generation to meet the small 10MW peak load. The effects of solar are thus quite simple, with displacement of diesel generation only.

6.1 SOLAR SYSTEM SAVINGS

Total system savings are summarized in Figure 6-1 for the Brayton cycle with and without hybrid. Almost all of the savings derives from displaced diesel fuel. Since the solar energy displaces a single type of conventional fuel, the total savings are essentially independent of solar penetration level until the point where solar capacity exceeds the peak load. The hybrid fuel system is also effective in displacing both additional capacity and expensive diesel fuel.

6.2 CAPACITY IMPACTS

Capacity impacts are summarized in Table 6-1 and Figure 6-2. Only the high-speed 3 MW diesel generation unit is displaced by the solar system For this particular utility, the solar plant displaces conventional diesel to about 20% of the rated solar capacity for no-hybrid and about 30% for incremental dispatch hybrid. The hybrid system with peak-shaving dispatch should displace a significantly larger amount of capacity; this will be investigated in further analyses. At any rate, the capital costs for diesel are sufficiently low that they are not a major cost element.

TABLE 6-1. Solar Capacity Displacement
Isolated Government Utility

SOLAR PLANT	SOLAR PENETRATION (% OF PEAK LOAD)	CAPACITY DISPLACED* (MW)
BRAYTON No Storage No Hybrid	5.4 10.9 21.7	0.12 0.24 0.46
BRAYTON No Storage Incremental Hybrid Dispatch	5.4 10.9 21.7	0.17 0.35 0.70

*Only 3 MW diesel generation is displaced.

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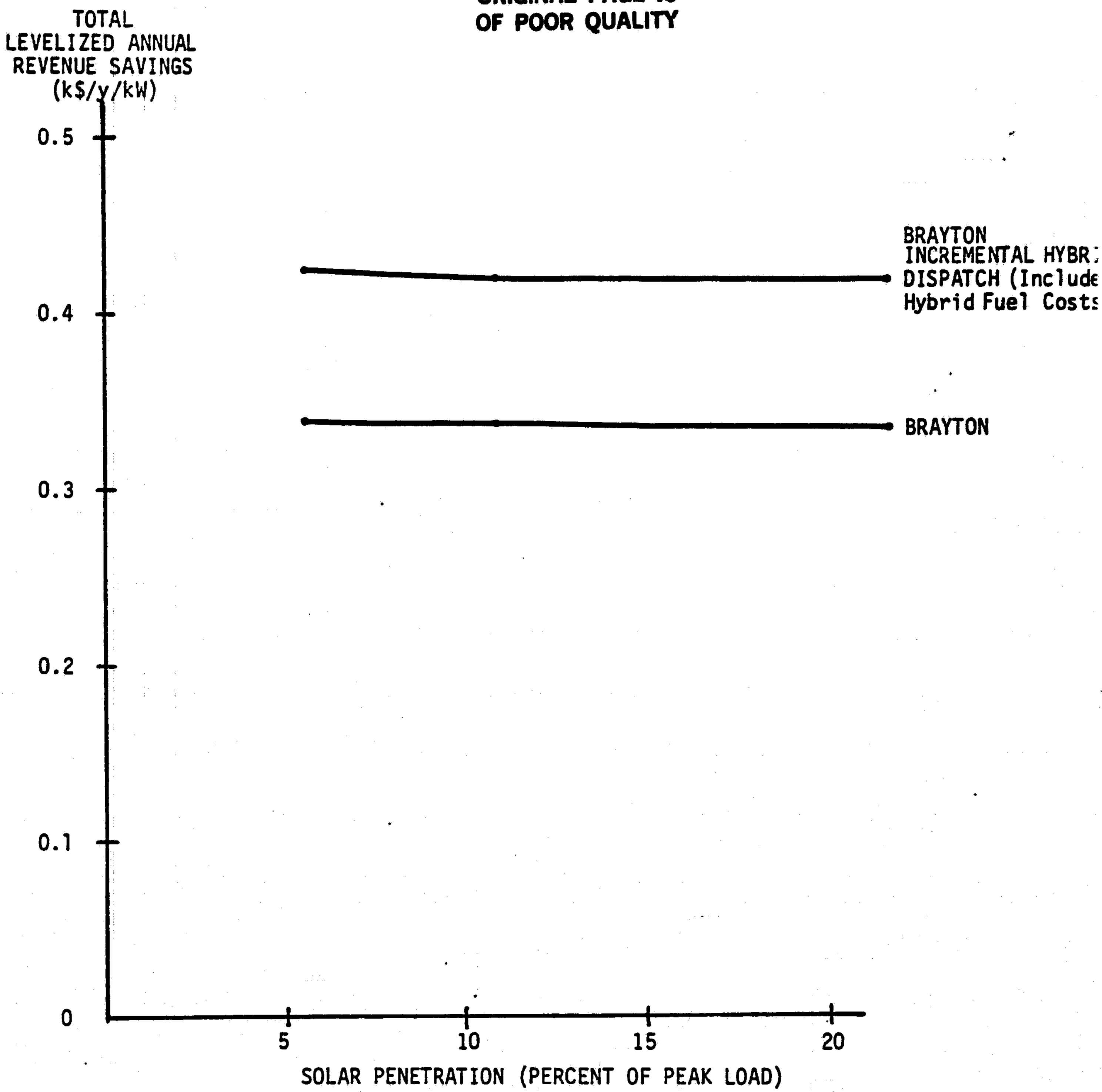

FIGURE 6-1. Solar System Savings—Isolated Government Utility

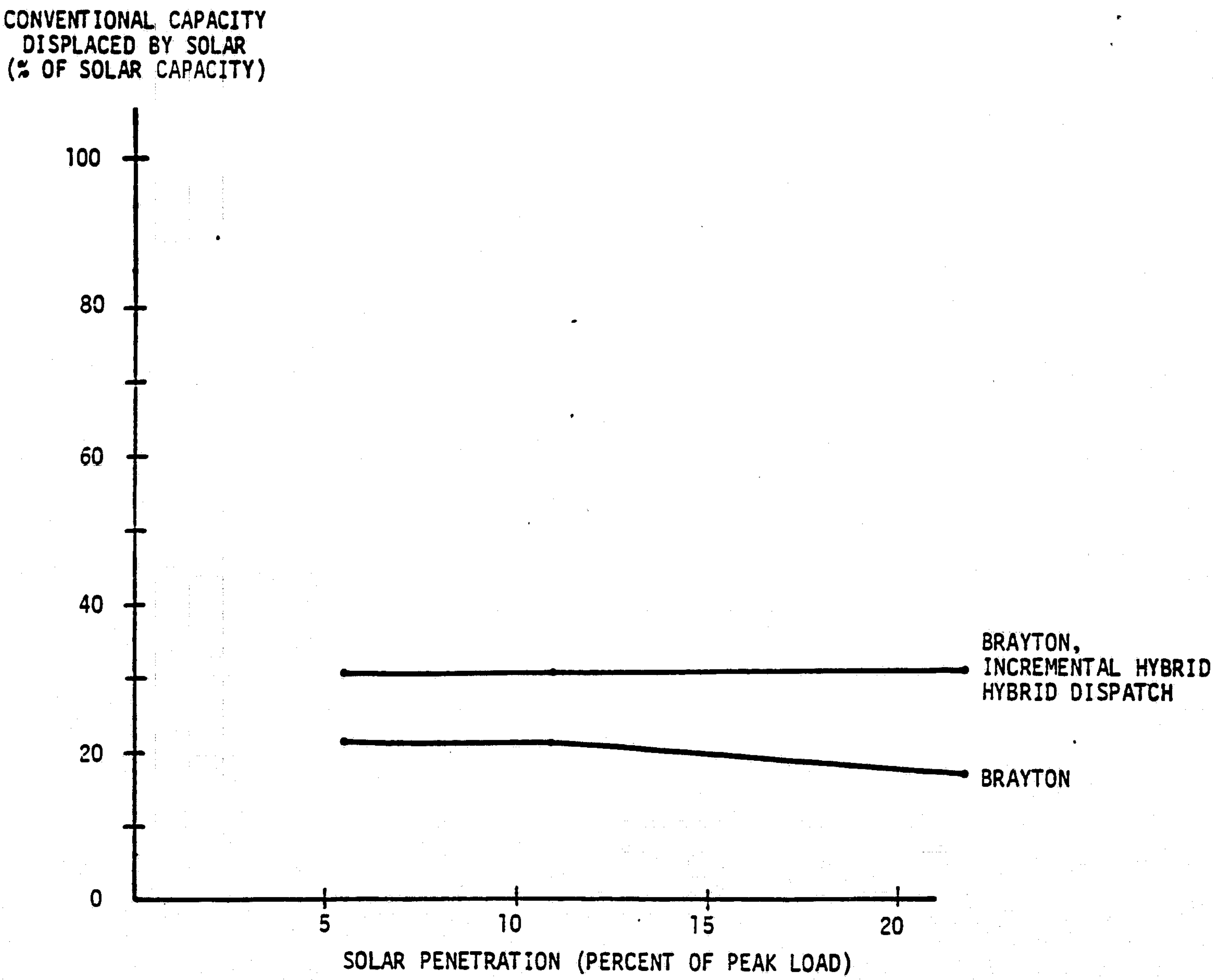

FIGURE 6-2. Solar Capacity Credit—Isolated Government Utility

6.3 FUEL AND CAPACITY SAVINGS

A breakdown of fuel and capacity savings is shown in Figures 6-3 and 6-4 for the Brayton configurations without and with storage, respectively. Fuel savings are by far the primary benefit of the solar generation. The hybrid system shows slightly higher capital cost savings and a net gain in fuel cost savings.

6.4 SOLAR SYSTEM BREAKEVEN COST

Solar system breakeven costs are shown in Figure 6-5 for the isolated government utility. Also shown are breakeven costs for the case of a nearby municipal which purchases power from the government utility and chooses to finance a solar plant. The breakeven costs are quite high because of the displacement of expensive diesel fuel and because of the favorable financing assumptions for these utilities. Because only one type of generation is displaced, there is little dependence on solar penetration level.

Solar breakeven costs for a variety of ownership alternatives are shown in Figure 6-6 for the no-hybrid configuration. Again, a wide dispersion exists depending on the financial criteria of the investor.

6.5 SOLAR SYSTEM NET WORTH

The solar system net worth as a function of installed system cost is shown in Figures 6-7 and 6-8 for the no-hybrid and hybrid configurations. Because the savings per unit solar are insensitive to the penetration level (at least below 100%), the optimum solar penetration is significantly higher than those values analyzed. For this type of situation in which solar is cost-effective in displacing energy from a single generation type, the optimum rated solar capacity will exceed 100 percent of the peak demand. This issue will be investigated further in subsequent analyses.

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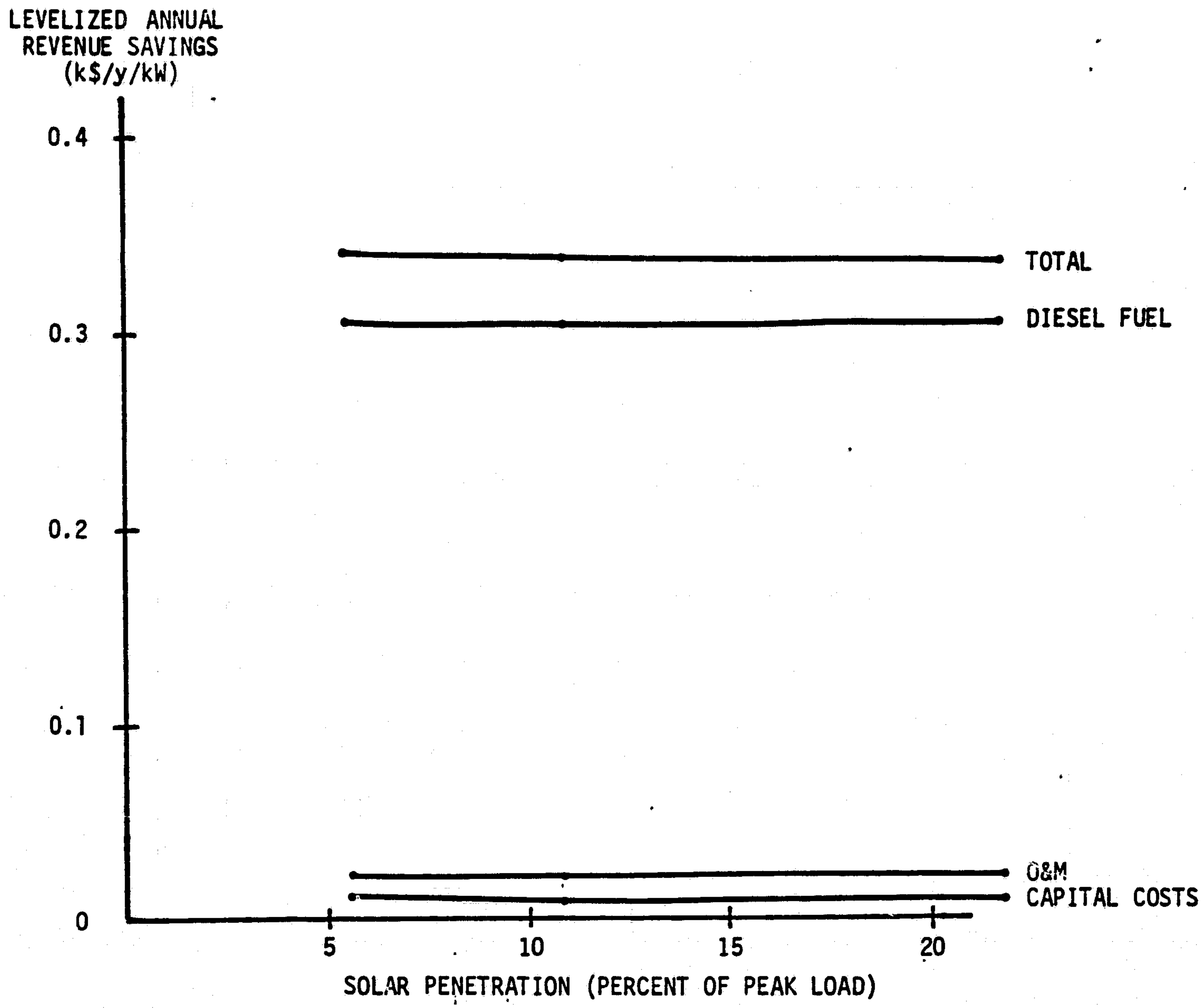

FIGURE 6-3. Solar System Savings—Isolated Government Utility
Brayton, No Storage, No Hybrid

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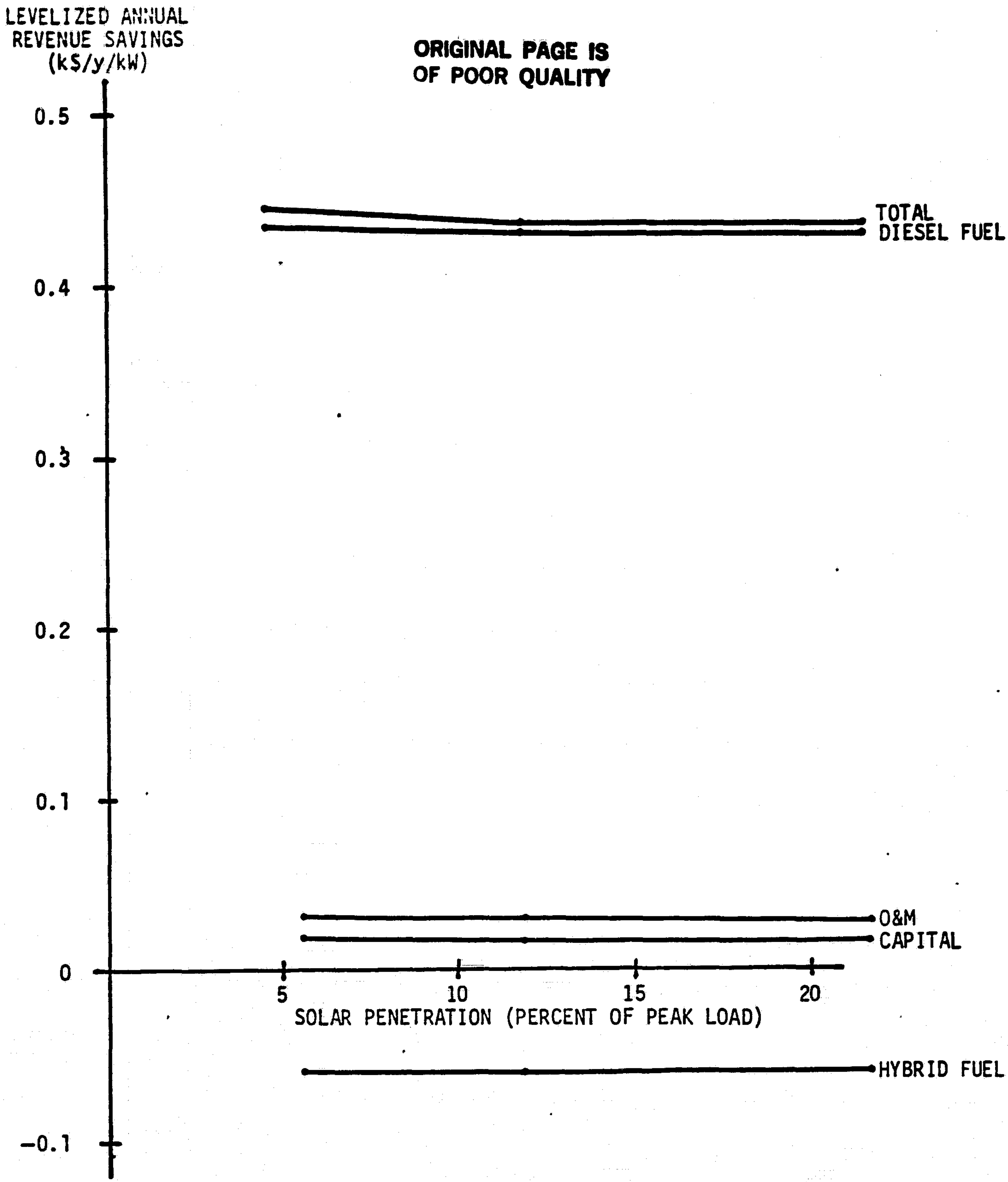

FIGURE 6-4. Solar System Savings—Isolated Government Utility Brayton, No Storage, Incremental Hybrid Dispatch

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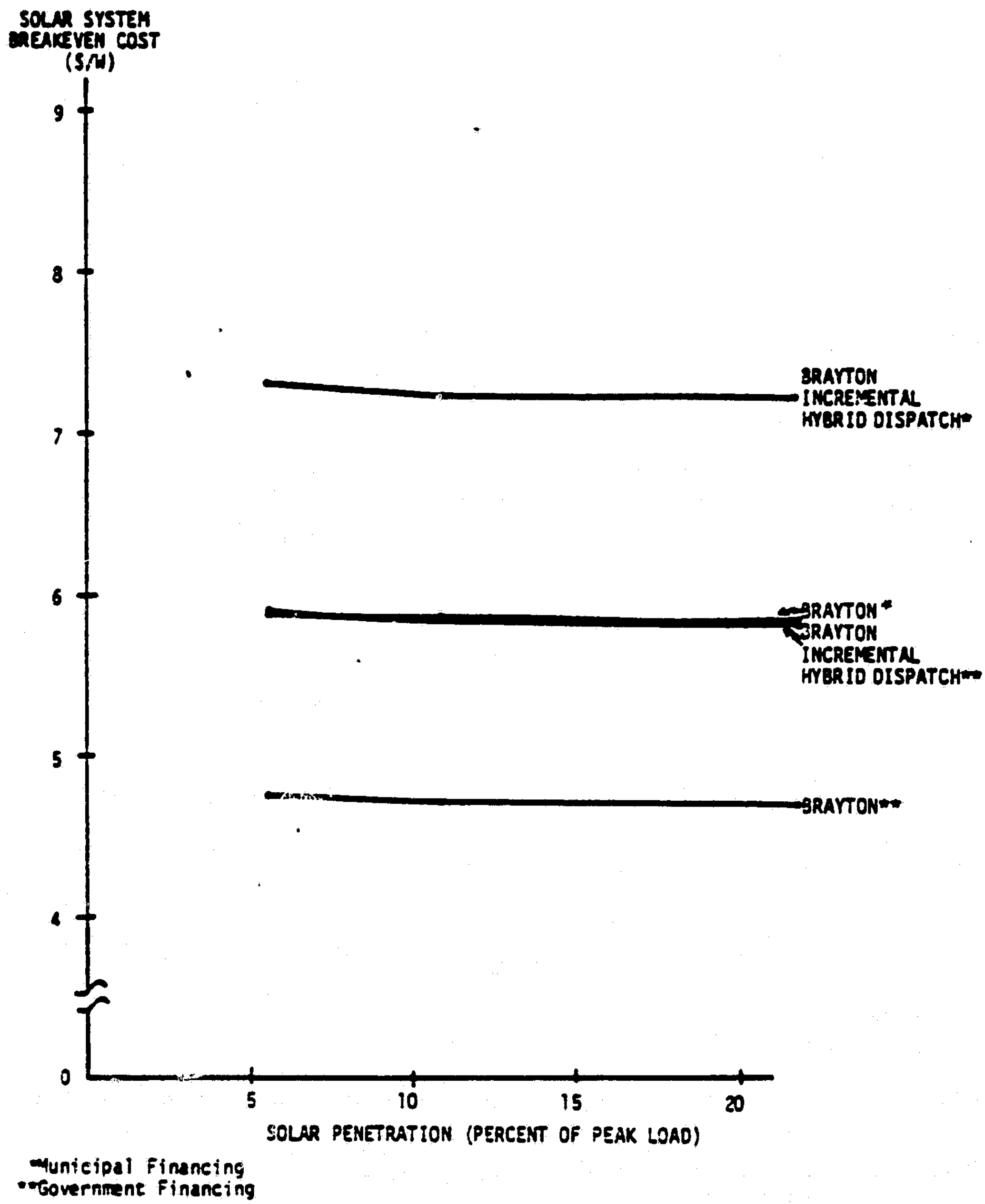

FIGURE 6-5. Solar System Breakeven Costs—Isolated Government Utility Government and Municipal Utility Financing

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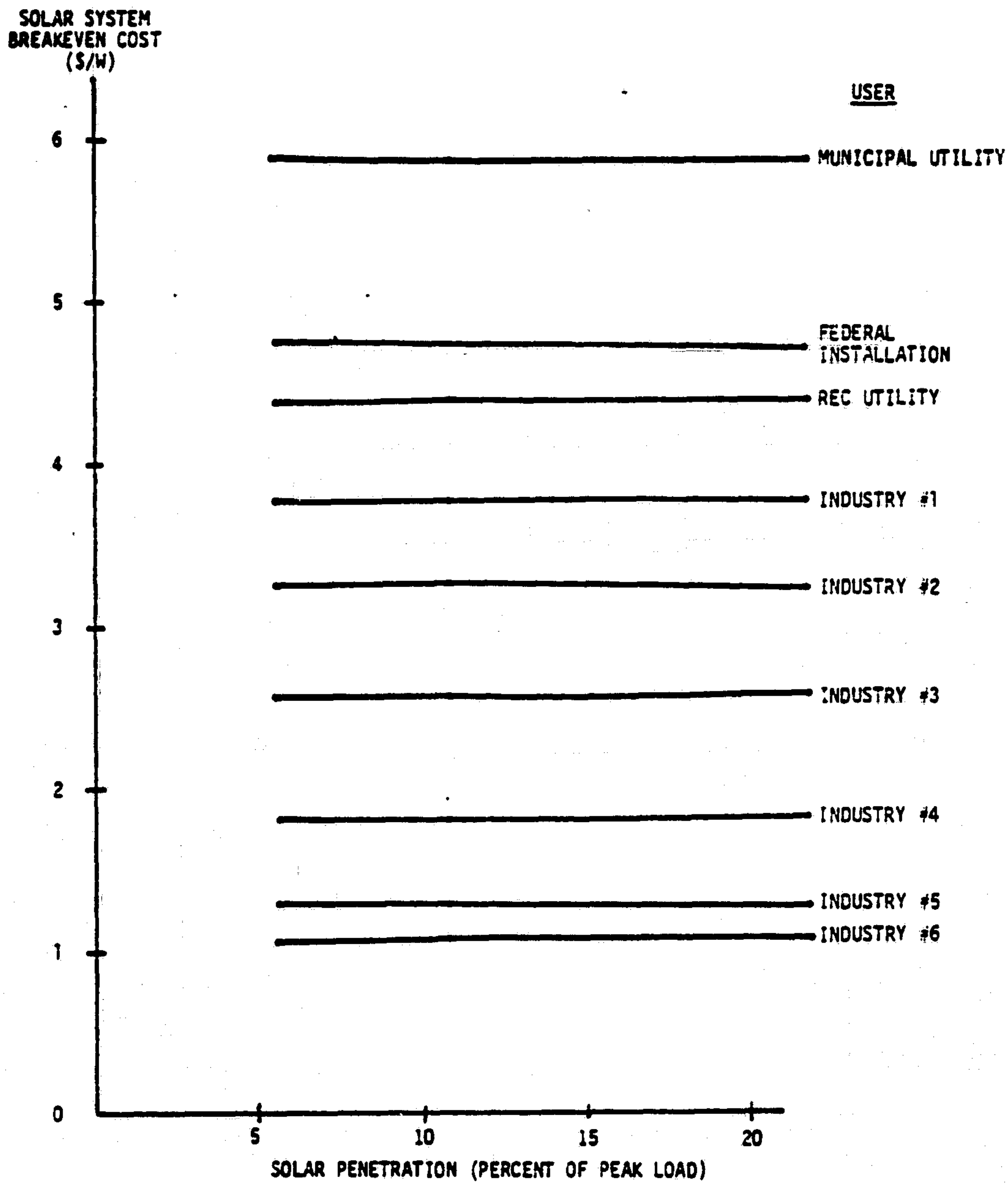

FIGURE 6-6. Solar System Breakeven Costs—Isolated Government Utility Brayton, No Storage, No Hybrid

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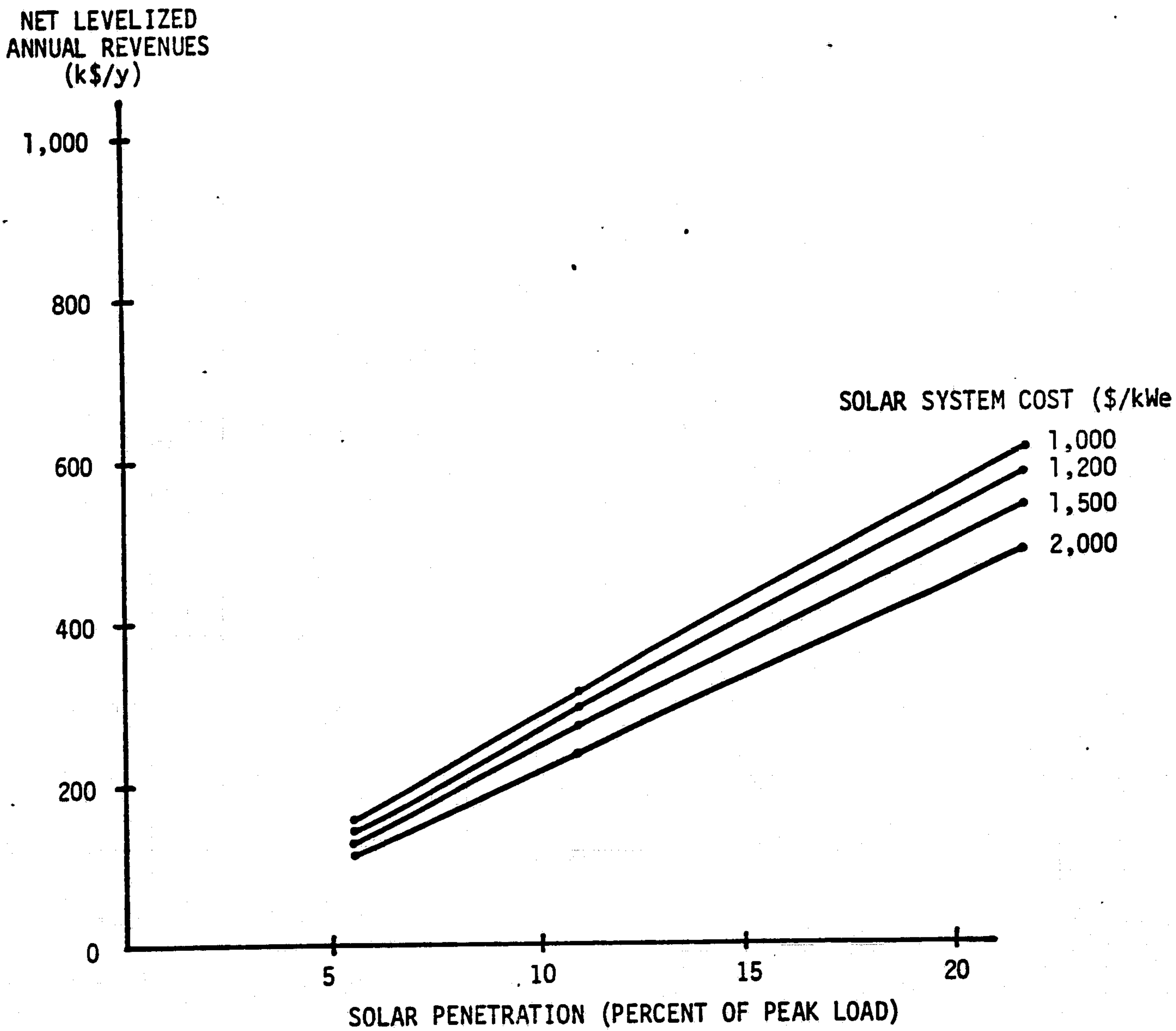

FIGURE 6-7. Solar System Net Worth—Isolated Government Utility Brayton, No Storage, No Hybrid

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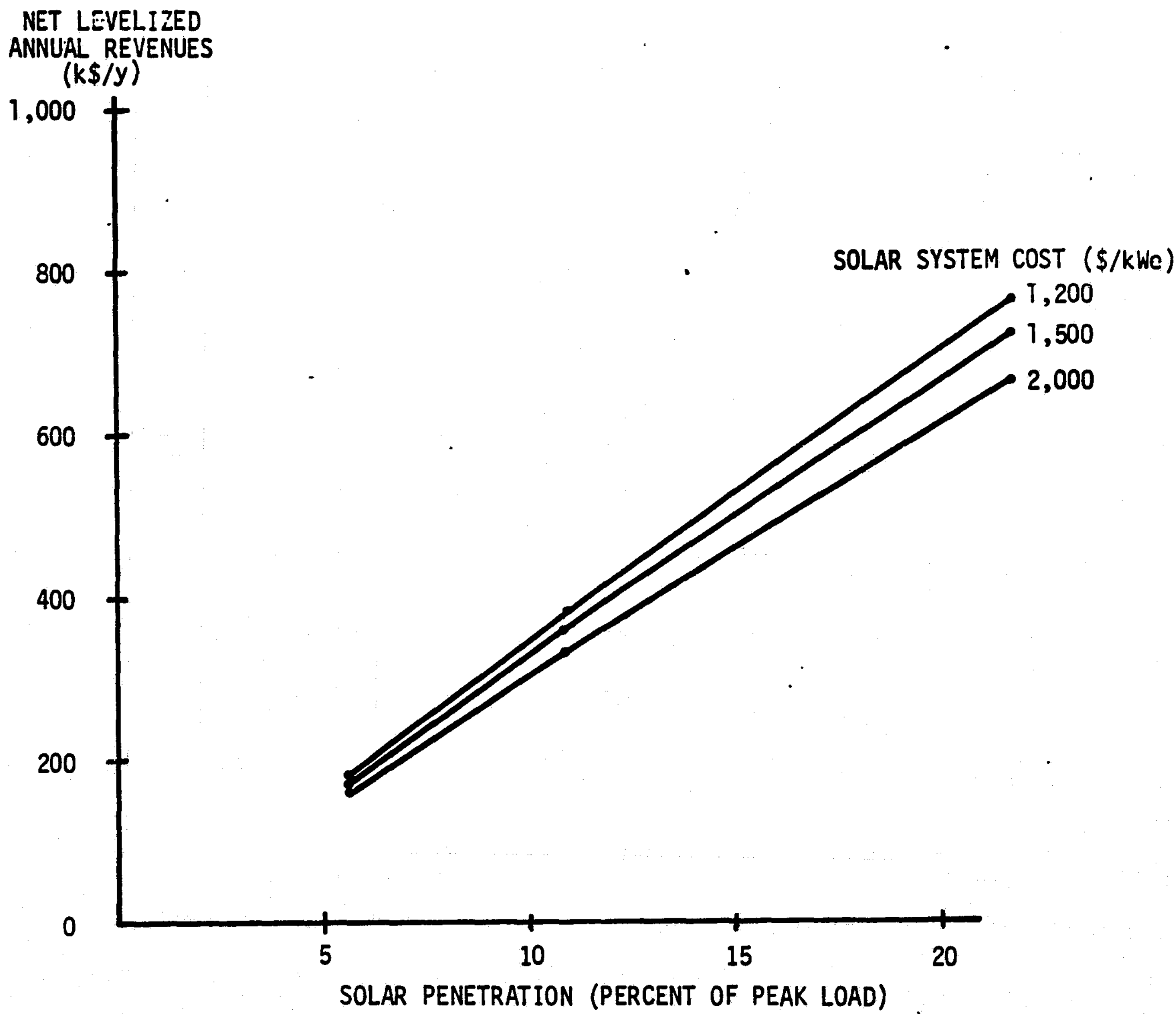

FIGURE 6-8. Solar System Net Worth—Isolated Government Utility
Brayton, No Storage, Incremental Hybrid Dispatch

SECTION 7

REGULATORY AND INSTITUTIONAL ISSUES

SECTION 7
REGULATORY AND INSTITUTIONAL ISSUES

Regulatory and institutional considerations will play a major role in addition to economics and technical performance in determining the utilization of solar thermal electric technologies. Key issues include ownership alternatives, government regulations, environmental impacts, and utility rate structures. The major institutions include the utility itself, the solar plant owner (who may be an energy consumer, utility, or third party investor), the state utility commission, and the Federal government. Federal and state regulations and utility policies are currently undergoing significan change with respect to solar energy systems, particularly for non-utility ownership. A brief discussion of some of these issues and how they are changing is provided in what follows:

7.1 PURPA

On November 9, 1978, Congress passed the Public Utility Regulatory Policies Act of 1978 (PURPA). PURPA thoroughly changed the way utilities were required to deal with non-utility producers of power. Before PURPA a non-utility power producer was heavily discouraged from operating in parallel with a utility. Any parallel operations subjected the producer to the Public Utility Holding Company Act, the Federal Power Act and similar state regulations. Moreover, no standard rates, terms, or interconnection requirements were offered to the producer.

PURPA changed this relationship. In terms of distributed solar power systems, the salient provisions of PURPA are as follows:

- solar units less than 30 MW and less than 50% owned by a public utility are deemed qualifying facilities (QFs) and are exempt in whole or in part from the Public Utility Holding Company Act, the Federal Power Act and similar state regulation.
- public utilities are required to interconnect with QFs on reasonable and nondiscriminatory terms, buy the QFs output at the utility's avoided cost for energy and capacity, and supply the QF with backup power and supplementary power at nondiscriminatory rates.

In 1979 and 1980, the Federal Energy Regulatory Commission (FERC) promulgated regulations under PURPA. For the most part, FERC's regulations gave the states great leeway in setting state specific rules implementing PURPA. The liberality of FERC's rules is seen in the tremendous variation among states in implementing PURPA. Some states (e.g., California, Texas) are in the process of extensive evidentiary hearings and discussions regarding equitable and efficient regulations. Other states (e.g., Pennsylvania, Hawaii) have more or less adopted FERC's broad guidelines. A third group of states (e.g., New Hampshire, Minnesota) appear to have gone well beyond FERC's minimum standards for small power producers. Still other states refuse to accept PURPA and are either actively contesting the legality of the law (e.g., Mississippi) or generally supporting such challenges (e.g., Georgia, Louisiana). Finally, there are states that have apparentsly assigned a low priority to PURPA and are just plodding along (e.g., Arkansas).

Many important solar states, including California, Texas and New York, have not completed their regulatory proceedings. Most states, however, have at least preliminary or experimental rates in effect. California for example, regularly publishes "Summary of Utility Rates for Purchases from Cogenerators and Small Power Producers," even though California has not produced final regulations. The California Public Utility Commission has ruled tht all QFs may revise their contracts in the future if the Commission ultimately decides on terms more favorable than those existing today. In New York, on the other hand, final regulations in the PUblic Service Commission's PURPA case (No. 27824) apparently depend on resolution of the Commission's investigation into Consolidated Edison Company's rules, regulations, and rates, governing on-site generators (N.Y.P.S.C. Case No. 27574). Meanwhile New York utilities have submitted PURPA rates and regulations under case no. 27824. In many of these submissions, the utilities are at variance with the proposals of the Commission staff in the Con Edison case.

7.2 METERING

Metering is an area of some conflict between the states and the utilities. In the interests of simplicity, economy, and producer incentives,

most states are permitting net energy billing for small QFs. Net energy billing (billing based on net consumption of energy) is an incentive to small producers for two reasons. First interconnection equipment, installation and billing costs (all borne by the Qf) are lower for net energy billing than for separate buy-sell interconnections with dual metering for onsite generation. Second, and more importantly, net energy billing allows the QF to sell power to the utility at the utility's retail rate not its avoided cost. For virtually all utilities, retail rates exceed avoided costs. For some utilities retail rates are several times greater than avoided costs. Utilities, of course, recognize that net energy billing subsidizes small producers at the expense of other ratepayers. Utilities thus favor separate buy-sell metering, sometimes called dual metering. Although most states permit both types of metering, the QF has the option to choose whichever suits his needs. Generally, the QF will select net energy billing.

As with other PURPA interpretations, the size of the QF eligible for net energy billing varies from state to state. For example, less than 100 kW (most states), less than 10 kW (Maine), less than 2,500 kWh/mo. (Minnesota), less than 72,000 kWh/mo. (Indiana). It should be noted that many states do not require time of use metering.

7.3 AVOIDED COST CALCULATION

FERC defines avoided cost as "the incremental costs to an electric utility of electric energy or capacity or both, which but for the purchase from the qualifying facility or qualifying facilities, such utility would gnerate itself or purchase from another source." The breadth of this definition is well known to utilities and fully reflected in the interpretations given it by the states.

Several states (Texas, Missouri, Maine, North Carolina) accept or are leaning towards probablistic production costing. Under the probabalistic costing method, the utility runs a production simulation of its existing and projected system and a production simulation of the same system at a lower level of demand (typically 100 MW lower or 10% lower, whichever is greater). The avoided energy cost is based on the difference in system production cost

per kWh at the higher and lower levels of demand. At least one state (Florida) rejects probabalistic costing in favor of deterministic costing. Under deterministic costing, actual hour by hour costs are calculated for the system.

A third method of calculating avoided costs is pool marginal costing based on specific units within a pool. Vermont, for example, bases its utilities' costs on the marginal costs of the New England Power Pool (NEPOOL). On the other hand, another NEPOOL state (New Hampshire) bases its avoided costs on specific new or relatively efficient units on the specific utility's system, not on the pool dispatched NEPOOL system. Colorado, a non-pool dispatched state, also bases its avoided costs on specific new units. Finally, some states permit a mix of methods. Nevada allows Sierra Pacific Power to unit cost and Nevada Power to probabalisticaly cost.

Translating these methods into actual avoided costs is not at all straightforward. FERC rules permit technology specific tariffs. Thus, utilities that can identify different avoided costs for various technologies may have to establish separate tariffs for each technology or similar groups of technologies. Although not widespread, technology specific tariffs do exist. Oklahoma, for example, has one tariff for wind energy and another for photovoltaics and stored hydro.

To update their avoided costs, utilities are also permitted a broad range of techniques. Vermont requires avoided cost calculations based on a test year and then escalated by some inflation/escalation component. North Carolina requires utilities to update energy credits biannually with fuel adjustment factors used in ther interim. Colorado requires its utilities to update fuel and O&M quarterly.

Although fuel cost is the principal component of avoided cost, most states show some sensitivity to non-fuel related costs or savings. These non-fuel related savings may include variable O&M, inventory and fuel handling and transmission and distribution losses.

The states' treatment of avoided capacity differs as widely as their treatment of avoided energy. All states require firm power to be sold on a contract basis but not all states require firm power contracts before imputing some capacity value to a particular generation technology. North Carolina, for example, requires utilities to consider the cumulative effect on utility capacity requirements from QFs that are individually unreliable but may be collectively reliable based on unit diversity. Since North Carolina bases its avoided costs on probablistic costing, this exercise is valid. At the same time, however, Colorado, which bases its avoided costs on specific units, takes the confusing position that avoided capacity cost can also be determined by the system effects of individually unreliable units. Colorado states that capacity credit can be given independent of over-capacity on a particular utility's system.

Most states agree that for capacity purposes, marginal energy and capacity must be calculated as coming from the same unit. That is, firm peak energy receives an avoided cost based on peak energy and peak capacity. Firm base energy (or, firm energy that cannot be dispatched by the utility) receives a credit based on base energy and base capacity. However, capacity credit calculations often involve more complex tradeoffs among peaking, intermediate and base generation. For example, many utilities faced with increasing peak energy demands will seek to serve that demand by installing a new, efficient base unit and pushing an older, less efficient unit up the loading order to serve the peak. Thus, in many cases, a utility's marginal capacity is base capacity regardless of the events taking place at the top of the loading curve. In general, the benefits of solar power plants can be very sensitive to the regulatory climate and the characteristics of the specific utilities and plant owners.

PART II

REQUIREMENTS DEFINITION

SECTION 8

REQUIREMENTS DEFINITION APPROACH

SECTION 8

REQUIREMENTS DEFINITION APPROACH

The overall objective of the requirements definition is to establish a general engineering description and first level requirements set for a selected set of system configuration/application/region combinations. The approach to achieve the requirements definition consists of the following steps:

- Specify the baseline design
- Identify system design requirements
- Estimate system costs
- Develop first order sensitivity estimates of system cost/performance.

Development of a system design is based on prior solar thermal system designs as reported in the literature and on standard practices used by Black & Veatch in design engineering of power plants. For each case (concept), a meaningful design was prepared which serves as a basis for the preparation of system cost estimate. Although optimization of these designs through trade-off studies is beyond the scope of this study, some insight to optimization is provided by the sensitivity studies.

The key elements of the requirements definition approach are described in what follows.

8.1. SPECIFY BASELINE DESIGN

A baseline design for each case will be developed with the objective of providing a qualitative/quantitative design summary description. The baseline design will concisely define plant characteristics reasonable for the system in question, though it may not be the "only" possible design or necessarily the "best" design; the design basis will be engineering experience and standard practice for conventional aspects of the plant and prior designs available in the literature for the parabolic dish solar system-

unique aspects of the plant. Where key data are not readily available to provide a design basis, engineering judgement shall be applied and explained. Design studies and analyses to develop original designs or to assure compatibility of all system components are beyond the scope of this task but technical rationale will be provided for the baseline design choices. Included in this baseline design will be the following:

- An 8-1/2" x 11" system schematic showing the plan arrangement of the system, with sizes, locations, and interconnections of subsystems indicated.
- Design conditions and baseline specifications (e.g., materials, temperature/pressure, flow rates, voltage/power etc.).
- Rated operating conditions.
- Subsystem key characteristics.
- Rationale in the design selection, assumptions implicit in the baseline design.

The level of detail provided will be adequate to generally describe the system consistent with the degree of system design developments.

8.2. ESTIMATE COST REQUIREMENTS

Based on the time frame and production rate conditions specified in each case and for the baseline design system characteristics, a system cost estimate will be developed. Costs for the solar unique subsystem/components will be based on the data base information as provided in Appendix C, with balance of plant costs developed on the basis of engineering experience and judgement. Elements of this task are as follows:

- Collect and project system costs
- Allocate and present costs in a uniform format with appropriate back-up data.

8.3. IDENTIFY SYSTEM DESIGN REQUIREMENTS

The objective of this task element is to identify representative, first-level requirements that will be placed upon subsystems/components in order to achieve the system characteristics specified for the baseline design. These requirements will reflect not only the performance capabilities necesssary to achieve the desired system function, but also the design requirements imposed by codes and standards, commercial product characteristics and good engineering practice. In other words, these requirements will provide insight to the nature and magnitude of task associated with designing, installing and operating the respective systems. The following considerations will be included in the requirements.

- Site: Pertinent site characteristics typical of the site will be determined. Because the system design must be able to tolerate the site characteristics, variance of those characteristics from site to site could influence system design. Instances where the variance may significantly impact the design will be identified and a brief explanation of why it influences the design will be provided.

- Functions: The functional capabilities that the system requires in order to operate will be identified. These will be presented in terms of operating modes and the corresponding actions required from the various subsystems.

- Design: The operating conditions (normal and emergency) will be outlined for the system; the significant requirements of codes will be highlighted. A system detailed design and subsystem interfaces would be guided by these design requirements.

- Safety: First-level system protection or safety problems and personnel safety and health hazards will be identified, and possible design responses/requirements will be highlighted.

- Codes and Standards: Requirements in this area will be considered as a part of Design or Safety.

- Operation: First-level estimates of the resources required to effectively operate and maintain the system will be developed.

- Construction: The major activities of the system construction process (such as work schedule, site preparation, procurement times, time required for key work elements, and construction, erection/installation time) will be identified on a precedence diagram. A preliminary estimate of the total time required for installation will be developed.

8.4 DEVELOP FIRST-ORDER SENSITIVITY ESTIMATES

A limited number of first-order tradeoff/sensitivity estimates on cost, performance, and design requirements will be developed as a function of key site/subsystem variables. The objective of these sensitivity estimates is to provide a basis for identifying major cost/performance/design drivers, understanding their impacts, and estimating the first-order magnitude of these impacts. The sensitivity variables to be evaluated include the following:

- Subsystem cost - Effects for each subsystem of a 20 percent increase in component/installation costs.

- Subsystem efficiency - Effects for each subsystem of a 10 percent relative increase in efficiency.

- Subsystem size - Effects of changing subsystem size ratings by ± 50 percent for: storage capacity (including associated changes in unit turbine size or collector area), turbine size/collector area, modular dish size, modular substation size, and total system size.

- Installation variables - Impacts of potential methods for reducing installation and construction costs.

To limit the scope of the sensitivity analyses, all of the above variables will be evaluated for only two of the case studies. In addition, at most one additional key sensitivity variable will be evaluated for each of the remaining case studies.

SECTION 9

IDENTIFICATION OF REQUIREMENTS DEFINITION CASE STUDIES

SECTION 9

IDENTIFICATION OF REQUIREMENTS DEFINITION CASE STUDIES

For system design and requirements definition it was necessary to select ten cases from the large number of applications addressed as part of the impacts analysis described in Sections 4 through 7. Each case was characterized as follows:

- Identify the application/user/site
- Identify/select system configuration and concept (size range, central vs. dispersed turbine cycle, storage, hybrid, backup, etc.)
- Identify subsystems/components
- Identify system major characteristics.

To develop a generic and broadly applicable set of system requirements, and to achieve the objectives of the requirements definition, the following criteria were used in the selection of case studies:

- Evaluate a range of system configurations including
  - Central versus dispersed generation (at each collector).
  - A variety of thermodynamic cycles (organic Rankine, steam Rankine, open and closed Brayton, and Stirling).
  - Different heat transfer fluids (sodium, oil, and steam).
  - Storage, no storage, and hybrid fossil.
  - Cogeneration of electricity and process steam.
- Evaluate a range of ownership alternatives and sites
- Emphasize the most promising site locations and systems as identified from the impacts analysis results.

An overview of the cases selected for first order design analysis and requirements definition is provided in Figure 9-1. System configurations include all of those mentioned above; ownership alternatives include municipal utility, investor-owned utility, isolated utility, and industry; and sites included Phoenix, Fort Worth, and Barstow

Case	Location/Application	System Configuration	Conversion Cycle	Net Rated System Capacity	Concentrator Design	Energy Transport	Storage/ Hybrid	Sensitivity Studies
1	Fort Worth, Texas, Municipal Utility	Central	Six 1 MWe Organic Rankine Turbines, 427 C (800 F)	5.6 MWe	G.E.	Sodium 454 C (850 F)	5-Hour Thermal	Subsystem Size/Cost
2	Phoenix, Arizona, Isolated Government Installation	Dispersed	Open Cycle Brayton 871 C (1,600 F)	10 MWe	G.E.	Electric	Hybrid	None
3	Phoenix, Arizona, Investor-Owned Utility	Central	Nine 1 MWe Organic Rankine Turbines 371 C (700 F)	8.4 MWe	G.E.	Silicone Oil (Syltherm 800) 399 C (750 F)	5-Hour Thermal	Use Single 9 MWe Turbine
4	Phoenix, Arizona, Investor-Owned Utility	Central	Single Steam Rankine Turbine 510 C (950 F)	9 MWe	G.E.	Steam 510 C (950 F)	5-Hour Thermal	Turbine Inlet Temperature
5	Fort Worth, Texas, Industry connected to Municipal Utility	Central, with Process Heat	Single Non-condensing Steam Rankine Turbine 510 C (950 F)	6 MWe	G. E.	Steam 510 C (950 F)	5-Hour Thermal	Use 3 MWe Turbine
6	Phoenix, Arizona, Industry	Central	Single Steam Rankine Turbine 510 C (950 F)	9 MWe	G. E.	Steam 510 C (950 F)	5-Hour Thermal	None
7	Barstow, California, Large Investor-Owned Utility	Dispersed	Stirling Engine 810 C (1,490 F)	10 MWe	G.E.	Electric	3-Hour Battery	Subsystem Size/Cost
8	Fort Worth, Texas, Municipal Utility	Dispersed	Stirling Engine 810 C (1,490 F)	10 MWe	Acurex	Electric	None	Concentrator Size
9	Phoenix, Arizona, Isolated Government Installation	Dispersed	Closed Cycle Brayton 871 C (1,600 F)	10 MWe	Acurex	Electric	None	Concentrator Size
10	Barstow, California, Large Investor-Owned Utility	Dispersed	Organic Rankine 427 C (800 F)	10 MWe	Acurex	Molten Salt 454 C (850 F) Electric	3-Hour Thermal, at Each Collector	5-Hour Storage

*1980 Dollars.

FIGURE 9-1. Cases Selected for Requirements Definition

SECTION 10

REQUIREMENTS DEFINITION RESULTS

SECTION 10

REQUIREMENTS DEFINITION RESULTS

The detailed results of the requirements definition task are summarized in this section for each of the ten cases. All of the designs are based on a 1990 time frame assuming that technologies and markets are sufficiently mature for mass production costing.

A summary of the system concepts and cost estimates for the ten cases is presented in Figure 10.0-1. The system concepts selected represent a wide range of design alternatives. The key concepts characterized include the following:

- Central generation and dispersed generation (at each collector).
- A variety of thermodynamic cycles (organic Rankine, steam Rankine, open and closed Brayton, and Stirling).
- Different heat transfer fluids (sodium, oil, and steam).
- Storage, no storage, and hybrid fossil.
- Cogeneration of electricity and process steam.

As discussed previously, three design locations were selected for the cases: Fort Worth, Texas; Phoenix, Arizona; and Barstow, California. Location of the systems impacted sizing of the collector fields, as well as shipping costs. The type of application (e.g., municipal utility) somewhat impacted the indirect cost estimates, primarily through the cost of money during construction.

An inspection of system costs on a per kWe basis shows a large range of costs, from \$1,727/kWe to \$7,408/kWe. Cost differences can be attributed to several key factors. First, those systems having energy storage (Cases 1, 3, 4, 5, 6, 7 and 10) have significantly higher capital costs than would similar systems without storage. These higher costs are due in part to the added cost of the storage system, but even more to the increased collector field size necessary to accommodate the storage. Because these systems with storage produce greater annual energy, the higher capital costs do not imply equally higher cost of energy.

TABLE 10.0-1. SYSTEM CONCEPT, SITE, USE, AND COST MATRIX

Case	Location/Application	System Configuration	Conversion Cycle	Net Rated System Capacity	Concentrator Design	Energy Transport	Storage/ Hybrid	Sensitivity Studies	System Capital Cost*	System Cost* $/kWe	Comments
1	Fort Worth, Texas, Municipal Utility	Central	Six 1 MWe Organic Rankine Turbines, 427 C (800 F)	5.6 MWe	G.E.	Sodium 454 C (850 F)	5-Hour Thermal	Subsystem Size/Cost	40,209,000	7,180	High system cost related to high cost of piping, particularly for alloy steel.
2	Phoenix, Arizona, Isolated Government Installation	Dispersed	Open Cycle Brayton 871 C (1,600 F)	10 MWe	G.E.	Electric	Hybrid	None	25,401,000	2,540	Moderate power conversion costs and use of hybrid instead of storage lead to "moderate" system costs.
3	Phoenix, Arizona, Investor-Owned Utility	Central	Nine 1 MWe Organic Rankine Turbines 371 C (700 F)	8.4 MWe	G.E.	Silicone Oil (Syltherm 800) 399 C (750 F)	5-Hour Thermal	Use Single 9 MWe Turbine	62,230,000	7,408	Oil specified as lower temperature heat transfer medium for comparison with Case 1. Higher storage cost and lower conversion efficiency offset replacing of alloy steel of Case 1 with carbon steel pipe.
4	Phoenix, Arizona, Investor-Owned Utility	Central	Single Steam Rankine Turbine 510 C (950 F)	9 MWe	G.E.	Steam 510 C (950 F)	5-Hour Thermal	Turbine Inlet Temperature	56,784,000	6,309	High system cost related to high cost of piping.
5	Fort Worth, Texas, Industry connected to Municipal Utility	Central, with Process Heat	Single Non-condensing Steam Rankine Turbine 510 C (950 F)	6 MWe	G. E.	Steam 510 C (950 F)	5-Hour Thermal	Use 3 MWe Turbine	53,855,000	8,976	Cost per kWe misleading because process steam is utilized.
6	Phoenix, Arizona, Industry	Central	Single Steam Rankine Turbine 510 C (950 F)	9 MWe	G. E.	Steam 510 C (950 F)	5-Hour Thermal	None	56,146,000	6,238	Case 6 is redesign of Case 4 with a new piping system design. Small cost savings realized.
7	Barstow, California, Large Investor-Owned Utility	Dispersed	Stirling Engine 810 C (1,490 F)	10 MWe	G.E.	Electric	3-Hour Battery	Subsystem Size/Cost	36,200,000	3,621	Storage significantly impacts cost/kW when compared with Case 8.
8	Fort Worth, Texas, Municipal Utility	Dispersed	Stirling Engine 810 C (1,490 F)	10 MWe	Acurex	Electric	None	Concentrator Size	17,267,000	1,727	Low assumed costs for mature Stirling engine technology and market and lack of storage contribute to lowest system cost of 10 cases.
9	Phoenix, Arizona, Isolated Government Installation	Dispersed	Closed Cycle Brayton 871 C (1,600 F)	10 MWe	Acurex	Electric	None	Concentrator Size	27,072,000	2,707	Moderate power conversion costs and lack of storage contribute to "moderate" system costs.
10	Barstow, California, Large Investor-Owned Utility	Dispersed	Organic Rankine 427 C (800 F)	10 MWe	Acurex	Molten Salt 454 C (850 F) Electric	3-Hour Thermal, at Each Collector	5-Hour Storage	61,437,000	6,144	High power conversion unit and storage costs contribute to high system cost.

*1980 Dollars.

A second key factor in cost differences is the high cost of piping systems for those cases utilizing central generation (Cases 1, 3, 4, 5 and 6). For this study, piping systems were designed and costed on the basis of currently standard practices for power plants. Means for significant reductions in piping system costs have been proposed in another study*. Those reductions would be achieved by automated factory assembly and semi-automated field installation of components; further cost reductions were considered possible through the field application of flexible pipes to reduce installation costs and replace expansion loops.

A third factor in system cost differences is the high efficiency of Stirling engine cycles as opposed to other cycles (41 per cent, versus 35 per cent for the Case 4 steam Rankine cycle and down to 26 per cent for the Case 10 organic Rankine cycle). The high Stirling cycle efficiency results in a significant reduction in the required number of collectors, the most expensive elements of the system.

A fourth factor in the system cost differences is the assumed cost of power conversion equipment. The low cost systems utilizing Stirling engines (and, in particular, Case 8 for which there is no storage) reflectd a projected installed cost of about $200/kWe for Stirling engines (plus alternators and heat rejection), based on DOE cost goals for a mature technology and market. This cost per kWe is about one half of that projected for Brayton cycle units, and one third of that projected for the central generation Rankine cycle units. The ability to achieve the low system cost of Case 8 is dependent on achieving the mature technology and market for the Stirling engines.

In conclusion, from a capital cost perspective, the preferrd configuration is a dispersed generation system using a Stirling cycle power conversion. This selection is predicated on development of the Stirling engine to a mature technology, and upon reduction of costs through mass

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* For discussion of piping cost reductions see Section 10.6.1. The study noted is Reference 2 of Section 10.6.

production. A second key conclusion is that central generation systems do not appear to be attractive alternatives unless piping costs are reduced significantly. The cost effectiveness of storage depends on the interaction between solar system performance, utility load profiles, generation costs, and utility economic assumptions as discussed previously. However, the addition of storage clearly requires extensive capital costs due to increased collector field site as well as the storage subsystem itself.

10.1 CASE I: SMALL UTILITY WITH GRID CONNECTION--6 MWe

The system designed for Case I of Task 10 is a 6 MWe parabolic dish system located in Fort Worth, Texas, using a cluster of six 1 MWe organic Rankine cycle (ORC) turbines for central generation. The system has thermal storage capable of allowing generation at rated capacity for five hours. The system is connected to the grid of the Fort Worth municipal utility.

Selection of the Case I system configuration was based on results of Task 5-8 of this project performed by SAI. These results are cited in Section 4 of the Preliminary Case Study Report, which documents Task 5-8 for the small municipal utility case impact analysis[1]. That analysis showed that an ORC system with five hours of storage provided the highest breakeven costs of the cases studied. In Task 10, the Case I system is further defined to provide a more complete understanding of system capabilities, limitations, and costs.

Design of the system was based on a 1990 time frame. Using the 1990 time frame allowed two key design assumptions

- There is sufficient time for development of materials and equipment not commercially available at present.
- Production of key system components, in particular the concentrators, receivers, and power conversion units, will be at a rate sufficiently high to bring costs of these components down to a "mature" level.

The system was configured for a noon March 21 design point, with the design point insolation at 950 watts/m^2 (301 Btu/hr/ft^2). This insolation level is a typical value at noon on a clear day. Designing for the noon peak insolation assures that the system is able to handle peak solar power inputs. The collector system was sized so that the five hours of thermal storage was just filled on a clear March 21. The impact of this design specification is an engineering compromise in that some solar energy is lost through defocusing on clear longer summer days, and that storage is not completely filled on shorter days. On partially cloudy summer days the size of the collector field is likely to be appropriate for the system and the selected storage size.

10.1.1 System Description

The baseline system design for Case I has the following key characteristics; rationale for these design decisions are listed on Table 10.1-1.

- The 6 MWe capacity is met by utilizing six 1 MWe modules. Each module is virtually self contained, with a dedicated collector field, piping network, storage, and turbine.
- Thermal storage is of a series configuration (through storage), and utilizes two tanks (rather than the single thermocline tank).
- The organic Rankine turbines use Toluene as the working fluid, at an inlet temperature of 427 C (800 F).*
- The receiver working fluid (and storage medium) is liquid sodium.
- The field consists of twelve-meter (39 feet) diameter parabolic dishes patterned after the General Electric low cost concentrators.[10] Dishes are arranged in a 0.25 ground cover ratio, with a total land area of about 28 hectares (70 acres) 4.7 hectares [(11.7 acres) per module] required.

The following subsections amplify on the system design, and give system operational considerations.

10.1.1.1 System Design Requirements. This subsection presents specific design requirements for the Case I baseline system. Topics addressed include the following

- Site conditions,
- Site arrangement,
- System design point requirements,
- System functional requirements, and
- Standards and regulations.

Site Conditions. The site for the Case I system is in the vicinity of Fort Worth, Texas. It is assumed that the site selection can be made to minimize site preparation, erecting of electrical transmission lines, and other plant

*The upper limit on turbine inlet temperature is about 427 C (800 F). Above that temperature the increased rate of toluene breakdown causes harmful deposits.[4]

TABLE 10.1-1. KEY DESIGN DECISIONS FOR CASE I

Design Decision	Favoring Rationale	Opposing Rationale
Use six 1 MWe modules rather than single 6 MWe module.	• 1 MWe ORC turbine has relatively good economy of scale. • 1 MWe module is good building block size for systems in the 1-10 MWe range.	• Overall system cost is expected to be higher with modular approach.[3]
Turbine/Storage location at collector field perimeter rather than field center.	• Less degradation of insolation/concentrator reflectivity due to cooling tower effluent. • Safety considerations placing primary personnel working areas outside the sodium network.	• Somewhat higher piping costs due to larger supply and return mains.
Series storage with intermediate heat transfer fluid (sodium).	• Capability to operate system at full load from storage (not attainable with parallel storage because the storage discharge temperature is lower than the charging temperature. • Intermediate fluid allows use of low-pressure piping and storage systems, reducing cost and maintenance.	• Collector must be run at higher temperature (less efficient) to allow for heat exchanger pinch point.
Toluene working fluid for ORC, at 427 C (800 F) inlet.[4,5]	• 600 kWe systems currently available using Toluene at 316 C (600 F). • Toluene is the only suitable organic fluid stable at 427 C (800 F).	• Lower inlet temperature would allow use of oil as intermediate fluid.

TABLE 10.1-1 (Continued). KEY DESIGN DECISIONS FOR CASE I

Design Decision	Favoring Rationale	Opposing Rationale
	• Technology exists to push temperature higher. • Cycle efficiency increased by higher inlet temperature.	
Liquid Sodium as receiver and storage working fluid.(6,7,8,9)	• At 454 C (850 F) the choice is Syltherm 800, molten salts, or sodium. • Syltherm 800 system would require pressurizing to about 150 psig, thereby increasing costs. • Syltherm 800 storage cost is about $13,000/MBtu versus $3,500/MBtu for sodium. • Extensive experience exists for sodium systems. • Sodium has higher thermal diffusivity than does oil or salt. • Sodium has lower freeze temperature [98 C (208 F)] than does molten salt, thus reducing the potential for piping freeze up.	• Less severe fire protection problems for molten salts. • Syltherm 800 has lowest "freeze" point.
Two tank storage system	• High thermal diffusivity of sodium would cause large thermal degradation of one tank thermocline system.	• Thermocline system is somewhat less expensive

support items such as access roads. Table 10.1-2 lists site conditions assumed.

<u>Site Arrangement</u>. The physical arrangement for the Case I system is shown on Figure 10.1-1. The six 1 MWe modules are controlled from a central control building, which also houses maintenance vehicles and equipment. Apart from the centralized control and the electrical interfacing of the modules, each module essentially operates as an autonomous unit. The baseline design has the turbine and storage for each module located at the module boundary, with the cooling tower furthest removed.

<u>System Design Point Requirements</u>. The baseline system was designed to provide rated power (6 MWe gross, 5.6 MWe net) at noon March 21. Figure 10.1-2 shows the functional configuration of the system as well a identifying design point temperatures, pressures, flow rates, and power traces. Design details for the individual subsystems are listed on Table 10.1-3.

<u>System Functional Requirements</u>. The previous section on system design point characteristics has described the Case I system configuration as well as design point temperatures, flow rates, and powers. This section identifies various system operating modes and the functional roles of the various subsystems in achieving those modes.

The overall system has been designed for a rated net power output of 5.6 MWe. The storage capacity allows rated operation for five hours in the absence of solar power. The sizing of storage was conducted such that the system could be operated on a clear March 21 as shown on Figure 10.1-3a, where the delay between the end of solar operation and the beginning of generation from storage could be any length of time from zero to several hours (recognizing that thermal losses ultimately would somewhat deplete storage for long storage periods). A more likely operating strategy with continuous turbine operation would be as shown on Figure 10.1-3b. Because series storage is utilized, the turbine can operate at rated conditions irrespective of the sun, so long as stored energy is available. This is contrasted with parallel storage systems in which generation from storage requires derated turbine operation due to second law fluid temperature reductions.

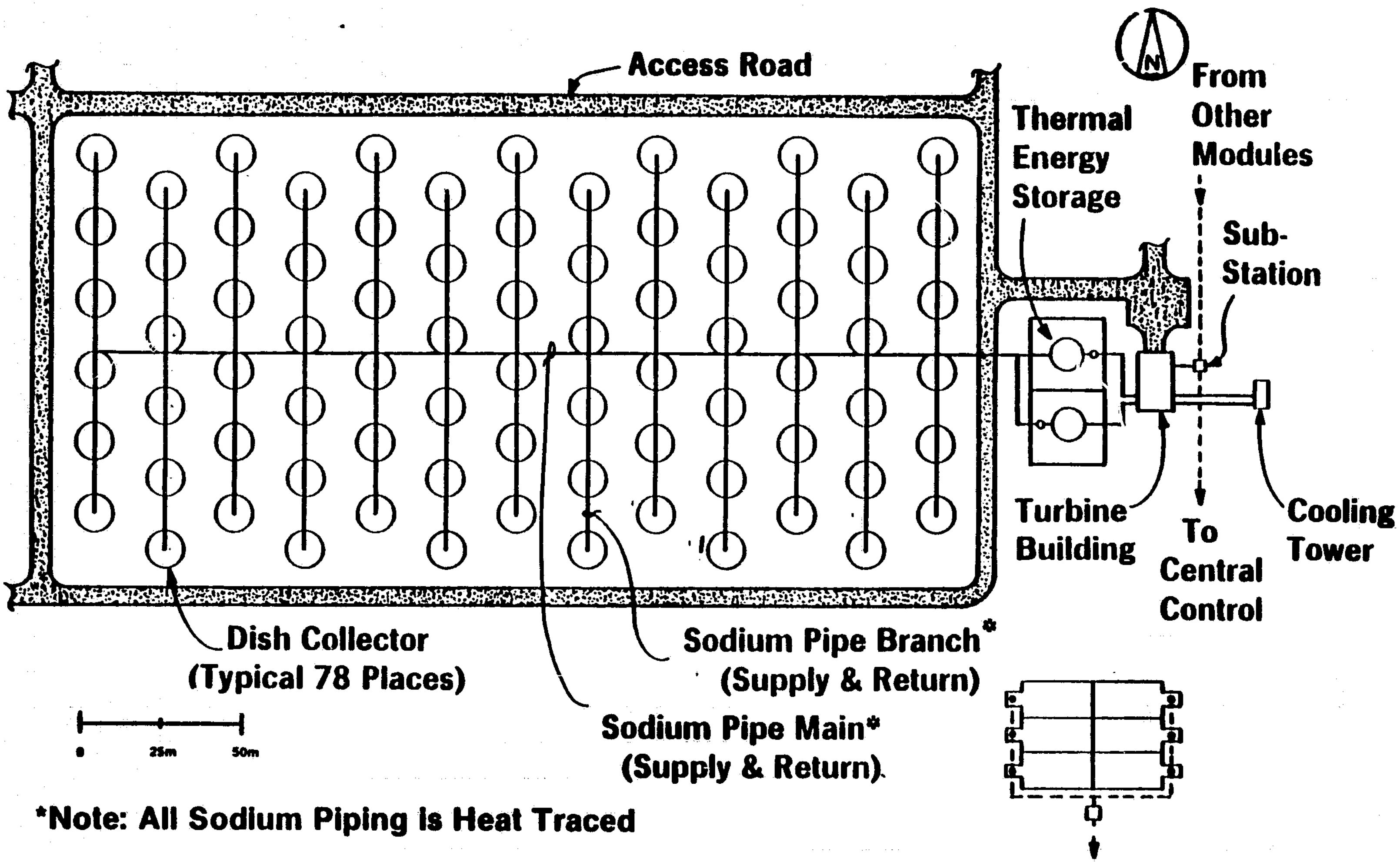
TABLE 10.1-2. SITE CONDITIONS (FORT WORTH, TEXAS)

Environmental Conditions (2, 10)

- Maximum Temperature: 46 C (115 F).
- Minimum Temperature: -23 C (-10 F).
- Annual Average Temperature: 19 C (66 F).
- Maximum Windspeed: 121 km/h (75 mph).
- Average Windspeed: 18 km/h (10.9 mph).
- Prevailing Wind Direction: South.
- Average Precipitation: 76 cm/yr (30 inches/year).
- Average Direct Normal Insolation: 4.8 kWh/m^2/day (1,520 Btu/ft^2/day).
- Sufficient Water is Available for use of a Wet Cooling Tower.

Assumed Terrain

- Relatively flat, level land area.
- Competent bearing strata near surface.
- Seismic Zone: 0.
- Plant Site has few, if any trees.



*Note: All Sodium Piping Is Heat Traced

FIGURE 10.1-1 1MWe ORGANIC RANKINE CYCLE COLLECTION MODULE PLAN ARRANGEMENT

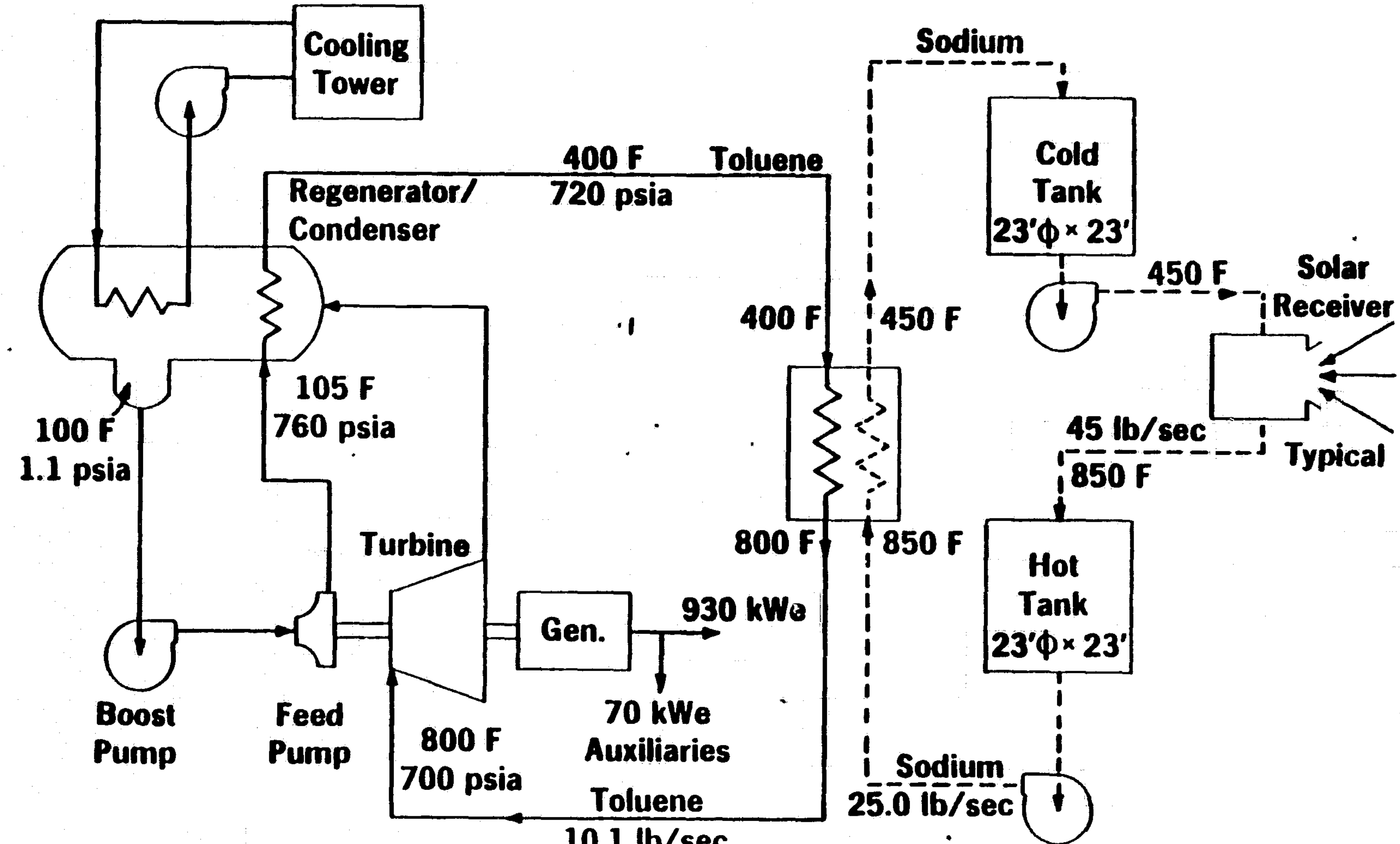


FIGURE 10.1-2 FUNCTIONAL FLOW DIAGRAM FOR CASE 1 SYSTEM

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TABLE 10.1-3. CASE I SUBSYSTEM DESIGN SUMMARIES

COLLECTOR SUBSYSTEM

Parameter	D. P. Value*
Concentrator[10]	
Dish Diameter, m (ft)	12 (39)
Effective Aperture Area, m^2 (ft^2)	111 (1,190)
Reflectivity	.84
Shading Factor	.94
Intercept Factor	.96
Concentrator Effectiveness	.74
Weight, kg (lb)	5,900 (13,000)
Receiver	
Outer Diameter, m (ft)	0.75 (2.5)
Aperture Diameter, m (ft)	0.25 (0.8)
Weight, kg (lb)	227 (500)
Inlet Temperature, C (F)	232 (450)
Outlet Temperature, C (F)	454 (850)
Power into aperture, kWt (MBtu/h)	79.9 (0.273)
Power to fluid, kWt (MBtu/h)	76.6 (0.261)
Mass Flow, kg/sec (lbm/sec)	0.26 (0.58)
Efficiency	0.96
Radiation Losses, kWt (Btu/h)	0.9 (3,100)
Convection Losses, kWt (Btu/h)	1.6 (5,500)
Conduction Losses, kWt (Btu/h)	0.8 (2,700)

*Design point.

ELECTRIC POWER GENERATION SUBSYSTEM[5,12]

Parameter	D. P. Value*
Cycle	Supercritical ORC
Working Fluid	Toluene
Turbine Type	Single-Stage Impulse
Thermal Input, kWt (MBtu/h)	3,278 (11.18)
Cycle Efficiency	0.318
Shaft Output Power, kWm (hp)	1,042 (1,397)
Turbine Inlet Temperature, C (F)	427 (800)
Turbine Inlet Pressure, MPa (psia)	4.8 (700)
Condensate Temperature, C (F)	38 (100)
Regenerator Effectiveness	0.65
Shaft Speed, rpm	12,000
Generator Efficiency	0.96
Gross Electric Output, kWe	1,000
Electric Auxiliary Load,** kWe	70
Net Electric Output, kWe	972
Boiler Toluene Inlet Temperature, C (F)	204 (400)
Boiler Toluene Outlet Temperature, C (F)	427 (800)
Boiler Sodium Inlet Temperature, C (F)	454 (850)
Boiler Sodium Outlet Temperature, C (F)	232 (450)
Toluene Flow Rate, kg/sec (lb/sec)	4.58 (10.1)
Sodium Flow Rate, kg/sec (lb/sec)	11.3 (25.0)

*Design point.

**Includes circulating water pump, cooling tower fans, controls, boost pump and gearbox lube pump. Does not include sodium pump or collector power requirements.

BALANCE OF PLANT

- Buildings.
  - -- Turbine (6).
  - -- Central Control and Maintenance.
  - -- Warehouse (spare parts inventory).
- Maintenance Equipment.
  - -- Truck.
  - -- Crane.
  - -- Washing Vehicle.
  - -- Tools.
- Fire Protection System.
- Plant Lighting System.
- Roads.
- Security Fence.

THERMAL ENERGY TRANSPORT SUBSYSTEM

- General piping layout as per Figure 10.1-1.
- Detailed piping layout similar in nature to Shenandoah Solar Total Energy Project piping layout.[13]
- 454 C (850 F) piping, valves, and fittings of 1-1/4 Cr, 1/2 MO.
- 232 C (450 F) piping, valves, and fittings of A106 Carbon Steel.
- Insulated to reduce thermal losses to 5 per cent of rated power.
- All valves of bellows-type construction.
- Pressure drop less than 138 kPa (20 psig).
- Heat traced electrically to prevent sodium freezing.
- All joints welded.

THERMAL ENERGY STORAGE SUBSYSTEM

Parameter	Value
Configuration	Two-Tank, Series Storage
Medium	Sodium
Capacity, MWht (h)	16.4 (5)
Hot/Cold Tank Temperature, C (F)	454/232 (850/450)
Hot and Cold Tank Dimensions	7m d by 7m (23' d by 23')
Sodium Inventory**, kg (lbs)	205,000 (451,000)

MASTER CONTROL SUBSYSTEM

- Central Control Mini-computer.
- Main Control Panel.
- Programmers Console.
- CRT Displays.
- Printer.
- Interface Hardware.
  - -- Turbine Controllers.
  - -- Collector Controllers.
  - -- Energy Transport Controllers.
  - -- System Instrumentation.

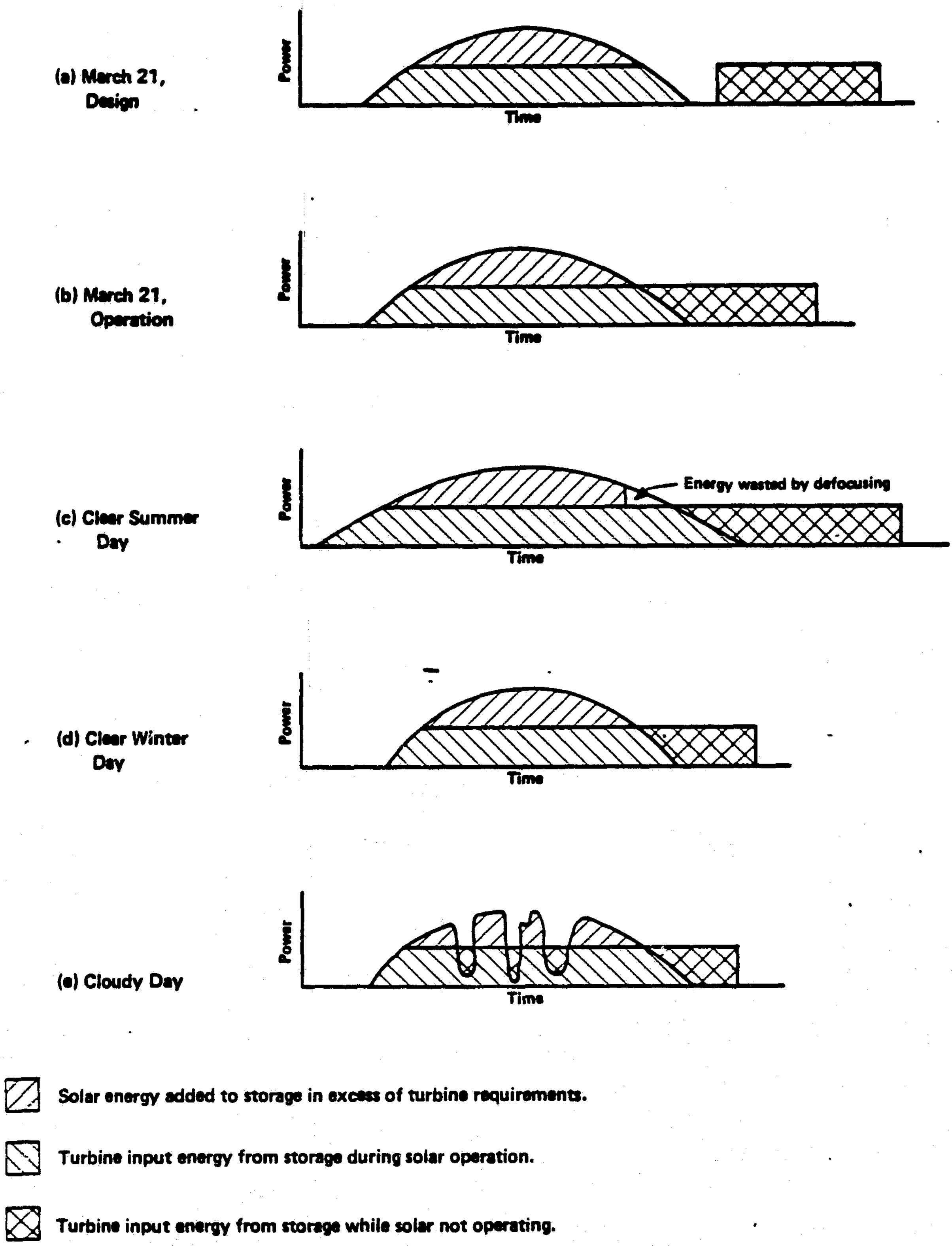

FIGURE 10.1-3 CASE 1 OPERATING MODES

Figures 10.1-3c and 10.1-3d show conceptually system operation on typical clear summer days and typical clear winter days. On summer days, the total energy to the field is such that collectors must be defocused, thereby "wasting" solar energy; on partially cloudy summer days defocusing is reduced or eliminated. On winter days, the collector field is unable to provide sufficient energy to fill storage completely.

All of the above operating modes assume that the system will generate rated power during virtually all of the day. This assumption is valid, in general, because economic dispatching of the solar power would always occur; from a dispatch perspective, solar power is essentially "free" in that operating costs (which ignore sunk capital expenditures) are very low. However, there may be times (especially in the winter when excess storage capacity is available) where the system might be utilized at lower outputs during certain portions of the day in order to provide peak power for a longer time period during times of peak grid demands, i.e., a load shifting strategy. Because the part load efficiency of the ORC turbine is good, the total energy output of the plant is not severely penalized by the use of such an operating strategy.

The isolation of the turbine from the solar source provided by the series storage permits the turbine control to be separate from collector field control. Further, it eliminates turbine transients during intermittent cloud cover (provided storage is at least partially filled). Figure 10.1-3e shows the impact of storage on operation during cloud passages. While the basic objective of using the storage is to lengthen the operating day as well as to provide a buffer for intermittent cloud cover, the availability of storage may be utilized for turbine start-up in the morning; this provides a smooth ramping of turbine power independent of solar conditions, thereby simplifying the start-up procedure.

In achieving the above system operating modes the Collector Subsystem must fulfill the following functional requirements.

- Two-axis tracking of the sun.
- Heat sodium from 232 C to 454 C (450 F to 850 F).

- Deliver up to 76.6 kWt (261,000 Btu/hr) of power to the sodium per collector.
- Operate in winds up to 50 km/hr (31 mph).
- Slew to stow in winds up to 80 km/hr (50 mph).
- Survive in stowed position for winds up to 120 km/hr (75 mph).
- Survive 1/4-g lateral seismic load.

The Energy Transport System, which for this case involves the movement of both thermal and electrical energy, must fulfill the following functional requirements.

- Transport sodium to and from the receiver with thermal losses not to exceed 1,800 kWt (6.1 MBtu/hr). This is 5 per cent of the thermal power from the field at the design point; the 5 per cent level is selected (for Case 1 and subsequent cases) on the basis of engineering judgment.
- Prevent sodium leaks.
- Prevent freezing of sodium (via heat traces).
- Provide for automatic isolation valves serving the six collector branches, and manual isolation of individual collectors to facilitate safety, reliability, and maintenance.
- Withstand 1/4-g lateral seismic load.
- Provide for a pressure drop not to exceed 20 psig at rated flow. The 20 psig pressure drop is based on engineering judgment and does not represent an optimization.

The Thermal Storage Subsystem must fulfill the following requirements.

- Provide storage capacity to allow thermal input to the turbines for 5 hours operation at rated power.
- Accept charge rates from 300 kWt to 6,000 kWt.
- Provide discharge rates from 150 kWt to 3,300 kWt.
- Maintain sodium quality and subsystem integrity.
- Provide for thermal losses to be less than 1 per cent of design point capacity per hour; the 1 per cent loss is based on engineering judgment.

The Electric Power Generation Subsystem has the following functional requirements.

- Transfer heat from sodium at 454 C (850 F) to Toluene at 427 C (800 F) at rates up to 3,300 kWt.
- Generate up to a gross power of 6 MWe (six modules).

The Central Control System must fulfill the following functional requirements.

- Allow dispatcher control of turbine output power.
- Send command signals to individual collectors to track, defocus, or stow.
- Monitor energy in thermal storage.
  - -- When storage is filled to capacity, to defocus collectors to match storage charge rate to its discharge and loss rates.
  - -- Command all collectors to track the sun when the system can utilize the full output of the collector system.
- Monitor system temperature, pressures, and flows.
- Provide warnings and alarms for faulty operation.
  - -- High temperatures and pressures.
  - -- Indications of leaks.
  - -- Sodium freeze.
- Provide built-in automatic system start-up and shut-down algorithms for the collector field. The start-up algorithm must assure that thermal storage is not thermally degraded by premature circulation of sodium through the collector field.

Standards and Regulations. The Case I system design is responsive to a number of laws, ordinances, codes, and standards. Table 10.1-4 lists applicable regulations, along with the more significant impacts of those regulations.

10.1.1.2 Operational Requirements. The day-to-day operational factors of the Case I system consists of four elements.

- Personnel
- Consumables

TABLE 10.1-4. APPLICABLE STANDARDS AND REGULATIONS

Requirement	Major Impact
Federal Laws and Ordinances Clean Air Act Noise Control Act National Environmental Policy Act Federal Water Pollution Control Act Toxic Substance Control Act	Design must protect against toluene and sodium leaks.
OSHA Codes and Standards Occupational Safety and Health Standards Safety and Health Regulations	Protection of workers from sodium leaks, fires. Insulation sufficient to prevent burns.
Association Codes and Standards (NFPA, ANSI, ASME, NEMA) National Electric Code Life Safety Code Boiler and Pressure Vessel Code	Fire protection in control buildings. Containment of sodium leaks from storage in berms. Toluene system design. Piping thickness, materials.

- Maintenance
- Safety

Operations personnel required to staff the plant include five full time workers. Three of these workers are plant operators; duty hours are structured so as to cover average system operation 17 hours per day, 7 days per week. During cloudy days, operators will perform routine inspections and maintenance tasks. The other workers will be detailed solely to maintenance tasks, the chief task being washing of the collectors. No allocation of administrative personnel has been made.

The primary consumable for the system will be collector washing fluid. A wash and rinse method is proposed, with a total water usage of 45,000 liters (12,000 gallons) per month [the basis is 95 liters (25 gallons) per wash per concentrator and monthly washing]. Other consumables are low in quantity; lubricants, toluene make-up [8 liters (2 gallons) per week, plus 3,800 liters (1,000 gallons) at each 5 year turbine overhaul],[14] nitrogen to provide a protective blanket for the sodium, and sodium make-up.

The primary maintenance activity will be the washing of concentrators. A washing vehicle which washes and then rinses the concentrator will be used. It is estimated that the cleaning process, which will be conducted once each month, will take 15 minutes per concentrator; this amounts to about 15 man-days per month. Other routine maintenance tasks will include inspection of system conponents for malfunctions (e.g., piping network for evidence of leaks; collectors for tracking problems). Valve maintenance for the sodium network is minimal because of the use of bellows type valves. Corrective maintenance problems will primarily involve concentrator tracking mechanisms. An inventory of spare parts (electronics, cables, plastic panels) for concentrators will be maintained.

Safety considerations for the Case I system center largely around the fire hazards associated with sodium and toluene systems. Design considerations discussed elsewhere are aimed at minimizing those hazards; however some operational safety considerations should be identified. Maintenance personnel working with the sodium carrying network and storage must wear appropriate protective clothing, including masks and gloves. Sodium

coming in contact with such clothing will freeze, and should be picked off and removed. Proper fire extinguishers (dry graphite is a UL approved agent for sodium fires) should be kept in buildings, vehicles and at strategic locations throughout the collector field. Large fires would probably be left to run their course; the size of the fire and its containment would be accomplished by isolation valves and by berms around storage tanks. Toluene leaks, if they should occur, would be restricted to the turbine building; therefore that building should be ventilated and gas detectors should be utilized. Smoking would be prohibited and all components within the turbine building would be specified for flammable environment usage

10.1.2 System Construction Considerations

Preliminary scheduling of the design, procurement, site preparation, and construction of the Case I System has been prepared. The total time period, from preliminary specifications through initial start-up, is estimated to be about 24 months. Figure 10.1-4 gives the construction schedule, detailing the various activity areas.

Assumptions used in preparing the schedule are as follows.

- A peak work force of 100 men is anticipated. This includes welders, dish erection crews, laborers, etc.
- An 8-hour day/20-day work month is assumed.
- Three four-man crews can assemble 12 dishes per week.[15]
- Foundations for dishes are drilled and poured at 1-1/2 per day.
- Pipe is laid at 0.4 km (1/4 mile) per day for combined supply and return piping.

10.1.3 System Cost Estimates

Capital cost estimates for the Case I System have placed the system cost at $40,209,000 in 1980 dollars. A breakdown of the various subsystem costs, along with assumed contingencies and indirect costs are listed in Table 10.1-5; estimated operation and maintenance costs are also included.

The bases for the various subsystem costs are as follows.

- A FOB concentrator cost of $\$100/m^2$ was used. This was in keeping with both the Task I data base,[2] and with DOE cost projections for large production levels.[17]

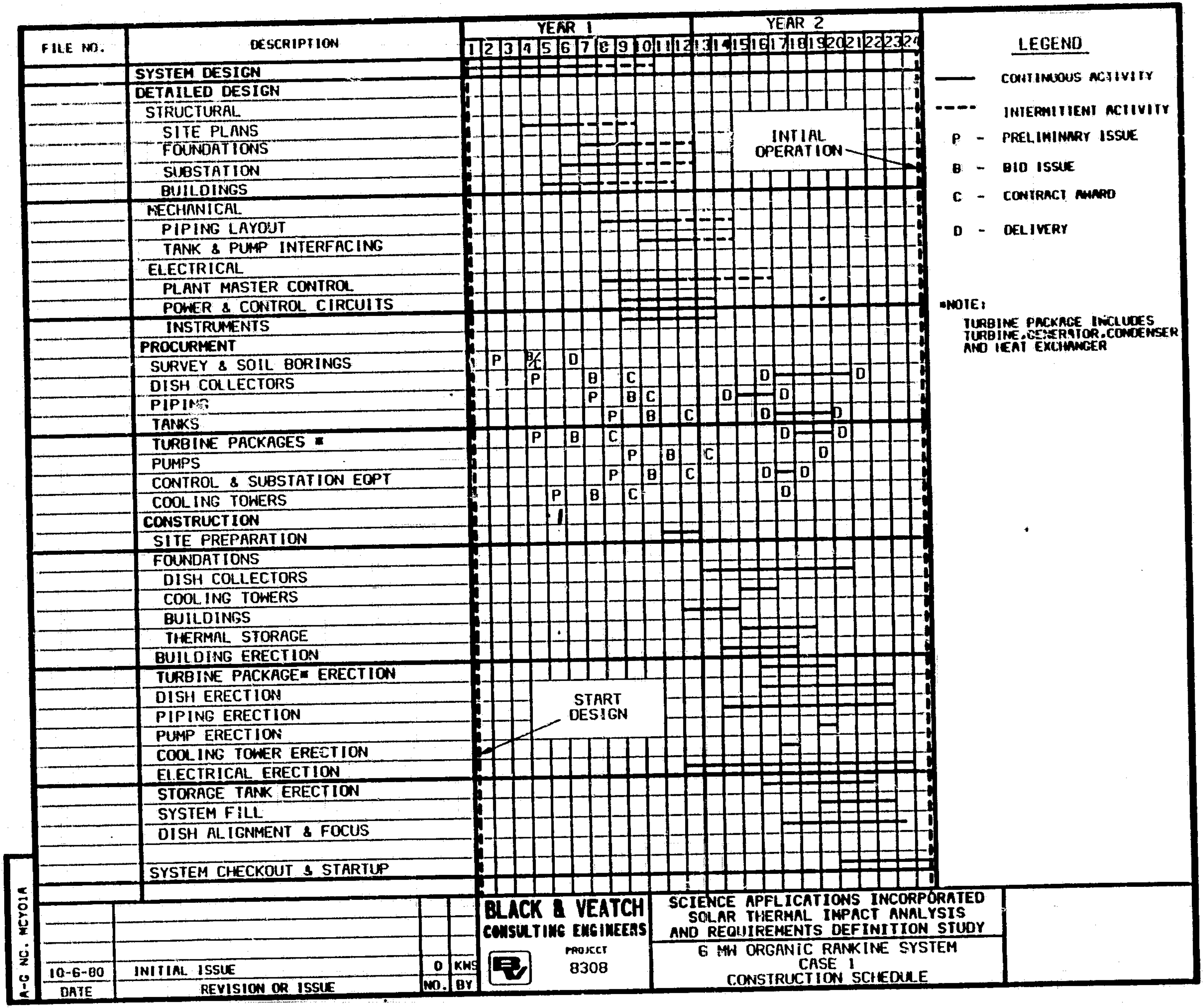

FIGURE 10.1-4 CASE 1 SYSTEM CONSTRUCTION SCHEDULE

TABLE 10.1-5. CASE I COST SUMMARY

Item		Capital Cost[a] $
Land		175
Site Preparation		100
Collector Field		7,992
Concentrators	$5,290	
Receivers	608[b]	
Concentrator/Receiver Installation	1,331	
Foundations (Installed)	763	
Thermal Energy Transport		8,256[c]
Piping and Insulation	1,158	
Valves and Fittings	1,740	
Heat Trace	240	
Instrument Air System	72	
Installation-support foundations, labor, equipment	5,046	
Thermal Energy Storage		3,207
Sodium	1,160	
Equipment	924	
Installation	1,123	
Electric Power Generation		3,470
Turbine, Heat Exchanger, Condenser	2,100	
Cooling Tower, Pumps, Piping	272	
Installation	1,098	
Electrical Distribution		1,963
Material	1,103	
Installation	860	
Master Control		1,250
Balance of Plant		691
Subtotal		27,104

TABLE 10.1-5 (Continued). CASE 1 COST SUMMARY

Item	Capital Cost[a] $
Contingencies (15 per cent)	4,066
Total Direct Costs	31,170
Indirects[d] (29 per cent)	9,039
Total	40,209

Operations and Maintenance Cost: $600,000/year

[a]1,000's of 1980 dollars.

[b]Includes shipping costs per G. E. shipment packaging criteria.(16)

[c]The basis for the high cost of the thermal transport system is illustrated in the table below, which gives a sampling of the material and installation costs for some of the system piping elements. Two factors are highlighted by this data. First, the cost per unit length of small diameter pipe (which constitutes a majority of the system) is, contrary to intuition, quite high due to installation costs. Second, the costs of materials and installation for the stainless steel alloy (1-1/4 Cr/1/4 Mo) making up the high temperature return line is substantially higher than costs of the comparatively low temperature carbon steel supply lines. Costs in the table include installation (but not material) for 2 inch valves in the carbon steel pipeline. Installation of expansion joints is included in all pipe costs. Pipe support material and installation costs, and insulation costs are not included.

	Carbon Steel		Alloy	
	Material $	Installation $	Material $	Installation $
2" Sch 80 [9,784 m (32,100 ft)]	120,000	620,000	378,000	1,760,000
3" Sch 40 [256 m (840 ft)]	8,400	20,400	22,200	32,400
6" Sch 40 [512 m (1,680 ft)]	49,200	63,600	120,00	156,000

[d]Indirect costs include engineering and construction management fees, administration and start-up costs, and AFDC. The 29 per cent value (Municipal Utility) differs from the 25 per cent value of Cases 2 and 9 (Government installations) and the 32 per cent value of Cases 3, 4, 5, 6, 7, and 10 in which the systems are part of privately owned utilities or industries. The primary difference in indirect costs is in the AFDC.

- Receiver costs of \$60/kWe were used, assuming a solar multiple of 1.0, and a turbine generator efficiency of 0.3 for the costing exercise. Again, this was found to be in agreement with DOE projections[16] and the Task I data base.[2]
- Turbine costs differing from the Task I data base were used since the turbine size (50 times larger than the 22 kW cited there) and the production (1/50 of the Task I value) are different. A cost estimate of \$350/kWe for the uninstalled turbine was based on learning curve volume reduction of a manufacturers estimate of \$540/kWe for 60 machines per year.[4]
- Other system costs were developed by the B&V cost estimating group from vendor information, B&V experience, and other published projects, based on first level material take-offs developed for the system design.
- Operation and maintenance costs are based on estimates from prior B&V solar projects, as well as published O&M projections for other projects.

10.1.4 <u>System Sensitivity Analyses</u>

Sensitivity analyses for the Case I System have been performed in order to provide a basis for identifying major cost/performance/design drivers and to determine their impacts. System sensitivities to the following five variables have been analyzed.

- Subsystem Cost
- Subsystem Efficiency
- Subsystem Size
- Site Variables
- Installation Variables

10.1.4.1 <u>Subsystem Cost</u>. The impact on total system cost of increasing subsystem cost by 20 per cent, one at a time, has been determined, the results of that analysis are summarized in Table 10.1-6. Key cost drivers are the thermal energy transport and collector subsystems.

10.1.4.2 <u>Subsystem Efficiency</u>. The sensitivity of system cost to increases in subsystem efficiency are shown in Table 10.1-7. The analysis assumed

TABLE 10.1-6. SENSITIVITY OF SYSTEM COST TO 20 PER CENT INCREASE IN SUBSYSTEM COST

Subsystem	Base Cost* $	Adjusted Cost* $	Adjusted System Cost** $	Per Cent Change
Collector	7,992	9,590	42,574	5.9
Thermal Energy Transport	8,256	9,907	42,652	6.1
Thermal Energy Storage	3,207	3,848	41,158	2.4
Electric Power Generation	3,470	4,164	41,236	2.6
Electrical Distribution	1,963	2,356	40,791	1.5
Master Control	1,250	1,500	40,579	0.9
Other	966	1,159	40,494	0.7

*In 1,000's of dollars.

**Total system cost including 20 per cent increase in a single subsystem cost, and including contingencies and indirects. Base total system capital cost is $40,209,000.

TABLE 10.1-7. SYSTEM SENSITIVITY TO INCREASES IN SUBSYSTEM EFFICIENCY*

Subsystem Altered (Efficiency Change)	Collector Subsystem	Storage Subsystem	Power Convs Subsystem	Energy Transport Subsystem	Decrease in System Capital Cost
Collector (0.71 to 0.78)	Nominally 10 per cent fewer collectors required	None	None	Nominally 10 per cent less pipe required; pipe size to individual collectors may increase	Nominal 8 per cent
Storage** (0.98 to 0.99)	Small impact	Small impact	None	Small impact	Small
Power Conversion (0.31 to 0.34)	Nominally 10 per cent fewer collectors required	Nominally 10 per cent less storage capacity required	Nominal 10 per cent small turbine required	Piping and pumps downsized to carry 10 per cent less peak flow nominally 10 cent per less pipe required	Nominal 9 per cent
Energy Transport (0.95 to 0.97)	2 per cent less collectors required	None	None	Very little	Nominal 0.9 per cent

*This analysis assumes that the system design is adjusted so as to maintain the designed output power. It also assumed that efficiency increases are achieved at no change of cost for the subsystem in question.

**Service storage "efficiency" is essentially 100 per cent if charge and discharge are simultaneous. Numbers given assume energy is stored several hours.

that other subsystems would be scaled so as to maintain the original system output. The greatest overall impact is through increasing of the power conversion efficiency; doing so allows decreasing of the collector size, thermal transport size, and storage size.

10.1.4.3 Subsystem Size. The impact of increasing/decreasing the various subsystems by 50 per cent cent has been evaluated. Several scenarios have been developed for adjusting the remainder of the system when one subsystem size is increased/decreased in size. Results are summarized in Table 10.1-8. The analysis was based on the following assumptions.

- Economy of scale for capital costs was not considered; e.g., a 50 per cent increase in total system size was assumed to increase system cost by 50 per cent.
- Land, site preparation, electrical, control, and balance of plant costs were assumed to vary directly with collector area. While this assumption is not rigorous, the error involved is quite small.

10.1.4.4 Site Variables. System sensitivity to changes in site variables has been analyzed. In general, evaluations of such sensitivities are dependent on specific site parameters. As such their quantitative evaluation is beyond the scope of this study. Also, in some cases (such as sensitivity to wind loading) cost sensitivity data is not available from equipment manufacturers. In other cases (such as sensitivity to topography) significantly different designs may be required. This analysis presents semi-quanitative and qualitative system sensitivity to major site variables in tabular form, Table 10.1-9.

10.1.4.5 Installation Variables. The sensitivity of overall system cost to reductions in installation costs are given in Table 10.1-10. It shows the relative impacts on system costs for 20 per cent reductions in the respective system component installation costs. The most sensitive per unit cost reduction is associated with the piping installation costs.

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TABLE 10.1-8. SYSTEM SENSITIVITY TO COMPONENT SIZE CHANGES

Sensitivity Scenario	Scenario Options		Impact on Overall System	Impact on System Capital Cost
	Label	Description		
50 per cent increase in storage size	A1	Maintain turbine size Increase collector size by 18 per cent Increase energy transport size by 18 per cent	Daily turbine production increased by 2.5 hours of rated power	Increases by 19 per cent
	A2	Decrease turbine size by 27 per cent Maintain collector subsystem size Maintain energy transport size	Power rating of plant decreases by 27 per cent Daily operation at rated power increases by 5.2 hours Total plant output energy decreases slightly	Increases by 2 per cent
	A3	Scale up all subsystems by 50 per cent	Plant power input increases by 50 per cent Plant daily energy output increases by 50 per cent	Increases by somewhat less than 50 cent
	A4	Do not change other subsystems	Increased storage allows changes in operating strategy Less energy lost by defocus in summer	Increases by 6 per cent
50 per cent decrease in storage size	B1	Maintain turbine size Decrease collector size by 18 per cent Decrease energy transport size by 18 per cent Increase turbine size by 29 per	Daily turbine operation reduced by 2.5 hours at rated conditions Rated power output of plant increases by 29 per cent	Decreases by 19 per cent Decreases by 2 per cent
	B2	Maintain collector size Maintain energy transport size	Daily turbine operation decreases by 3.1 hours Total daily energy output increases slightly	
	B3	Decrease turbine size by 50 per cent Decrease collector size by 50 per cent Decrease energy transport by 50 per cent	Plant rated power output decreases by 50 per cent Daily plant energy output decreases by 50 per cent	Decreases by 50 per cent

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TABLE 10.1-8 (Continued). SYSTEM SENSITIVITY TO COMPONENT SIZE CHANGES

Sensitivity Scenario	Scenario Options		Impact on Overall System	Impact on System Capital Cost
	Label	Description		
	B4	No changes in other subsystems	Some collectors will have to be defocussed when storage becomes full	Decreases by 6 per cent
50 per cent increase in turbine size/ collector area	C1	Increase storage capacity by 50 per cent Increase energy transport size by 50 per cent	See A3	See A3
	C2	Maintain storage capacity Increase energy transport size by 50 per cent	Rated plant power output increases by 50 per cent Daily turbine operation reduced by 1.7 hours Daily plant energy output increases by 50 per cent Some collectors will have to be defocussed when storage becomes full	Increases by 44 per cent
50 per cent decrease in turbine size/ collector	D1	Decrease storage capacity by 50 per cent Decrease energy transport size by 50 per cent	See B3	See B3
	D2	Maintain storage capacity Decrease energy transport by 50 per cent	Plant rated power output decreases by 50 per cent Daily plant energy output decreases by 50 per cent Oversized storage capacity permits greater flexibility in operating strategy	Decreases by 44 per cent
50 per cent increase of modular dish size	E1	Number of dishes kept constant Increase energy transport size by 50 per cent Increase storage capacity by 50 per cent Increase turbine size by 50 per cent	See A3	Increase by 50 per cent
	E2	Number of dishes reduced to maintain level of power collected Maintain size of storage and turbine	None	Uncertain impact

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TABLE 10.1-8 (Continued). SYSTEM SENSITIVITY TO COMPONENT SIZE CHANGES

Sensitivity Scenario	Scenario Options: Label	Scenario Options: Description	Impact on Overall System	Impact on System Capital Cost
50 per cent decrease of modular dish size	F1	Number of dishes kept constant Decrease energy transport size by 50 per cent Decrease storage capacity by 50 per cent Decrease turbine size by 50 per cent	See B3	Decrease by 50 per
	F2	Number of dishes increased to maintain level of power collected Maintain size of storage and turbine	None	Uncertain impact
50 per cent increase of modular subsystem size	G1	Increase collector size by 50 per cent Increase energy transport by 50 per cent Increase storage capacity by 50 per cent Increase turbine size by 50 per cent	See A3	See A3
50 per cent decrease of modular subsystem size	H1	Decrease collector size by 50 per cent Decrease energy transport size by 50 per cent Decrease storage capacity by 50 per cent Decrease turbine size by 50 per cent	See B3	See B3
50 per cent increase of total system size	I1	Increase number of modules by 50 per cent No change to subsystems in individual modules	See A3	See A3

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TABLE 10.1-8 (Continued). SYSTEM SENSITIVITY TO COMPONENT SIZE CHANGES

Sensitivity Scenario	Scenario Options		Impact on Overall System	Impact on System Capital Cost
	Label	Description		
	I2	Increase size of individual modules by 50 per cent Increase collector size by 50 per cent Increase energy transport by 50 per cent Increase storage capacity by 50 per cent Increase turbine size by 50 per cent	See A3	See A3
50 per cent decrease of total system	J1	Decrease number of modules by 50 per cent No change to subsystems in individual modules	See B3	See B3
	J2	Decrease size of individual modules by 50 per cent Decrease collector size by 50 per cent Decrease energy transport by 50 per cent Decrease storage capacity by 50 per cent Decrease turbine size by 50 per cent	See B3	See B3.

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TABLE 10.1-9. CASE I SENSITIVITY TO SITE VARIABLES

Variable	Baseline Design Basis	System Sensitivity
Insolation (vary by 10 per cent)	• Design point insolation at 950 watts/m^2. • Field sized to fill 5 hours storage on March 21 (clear day assumed).	• 10 per cent decrease of clear day insolation required 10 per cent increase in field size, with accompanying increase in piping and other field related items. • System capital cost increases by 8 per cent.
Wind Loading	• Concentrator and foundation design requirements. -- Operate in winds to 50 km/h (31 mph). -- Slew to stow in winds to 80 km/h (50 mph). -- Survive in stowed position in winds to 120 km/h (75 mph).	• Data on concentrator cost vs. design wind load not available.
Seismic Zone Criteria	• Concentrator design based on 1/4 g lateral acceleration. • Seismic Zone 0.	• Design is controlled by wind loading rather than seismic considerations; therefore, system design not greatly sensitive to seismic conditions. • Seismic Zones 3 and 4 may require higher than 1/4 g lateral acceleration criterion.
Soil Conditions	• Competent bearing strata near the surface assumed.	• Concentrator foundation cost is estimated to be 3 per cent of total system cost; therefore, only slight cost sensitivity is expected.
Topography	• Relatively flat, level land area with few trees. • Minimal site preparation. • Concentrator and piping layout based on flat, level land.	• Impacts of rugged terrain include the following. -- Large increase in site preparation costs. -- Reduced field performance due to increased mutual shadowing of concentrators or significantly increased piping runs and cost. • Land rising to the north permits higher ground cover ratio and more compact system.

TABLE 10.1-9 (Continued). CASE I SENSITIVITY TO SITE VARIABLES

Variable	Baseline Design Basis	System Sensitivity
Water Availability	• Makeup water is available for use in wet cooling towers (approximately 5.5 liters/sec [90 gpm]). • Auxiliary power requirements about 168 kWe. • Cooling tower costs about $216,000.	• Approximately 10 per cent increase in cost for system scaled to maintain some net plant output if dry cooling tower required. This includes the following considerations. -- Decreased cycle efficiency due to higher condensor pressure (about 3 per cent). -- Increased cooling tower costs (about 3.5 per cent system cost increase). -- Additional auxiliary power requirements (about 4 per cent of plant net output).

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TABLE 10.1-10. CASE I SENSITIVITY TO INSTALLATION COSTS

Item	Installation Cost* (per cent total) $	Per Cent Decrease in Total System Cost with 20 Per Cent Decrease in Installation Cost
Concentrators/Receivers	1,331,000 (4.9)	0.98
Concentrator Foundations	764,000 (2.8)	0.56
Thermal Energy Transport	5,046,000 (18.6)	3.72
Storage	1,123,000 (4.1)	0.83
Turbine	1,098,000 (4.1)	0.81
Electrical	860,000 (3.2)	0.64

*Prior to inclusion of contingencies and indirects.

10.1.5 Case I References

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17. Private communication to L. E. Stoddard, Black & Veatch, from John Lucas, Jet Propulsion Laboratory, August 4, 1980.

10.2 CASE 2: DISTRIBUTED GENERATION STAND ALONE 10 MWe

The Case 2 system design for Task 10 is a 10 MWe parabolic dish system using a distributed generation via hybrid solar/fossil open cycle Brayton (OCB) turbines mounted at the dish focal point. The system considered is to be utilized at an isolated government installation or military base located near Phoenix, Arizona. A diesel generator provides onsite back-up capabilities.

The selecton of this system for the Case 2 design is based on results of Tasks 5-8 of this project performed by SAI and documented in Section 6 of the Preliminary Case Study Report.[1] In that portion of the project, the potential impact of solar thermal systems on isolated government utilities, using Phoenix as the location, was analyzed. This analysis showed that the OCB with hybrid capabilities using an incremental dispatch procedure provided the highest levellized annual revenue savings if the displaced energy costs remain constant (independent of time of day). (The incremental dispatch of hybrid is defined as using hybrid to raise the OCB turbine to full power if solar input exceeds 30 per cent of rated power, and withholding hybrid if solar input is less than 30 per cent.)

In the Case 2 system design, the system was sized to produce 10 MWe (using solar power only) with a 950 W/m^2 (301 $Btu/hr/ft^2$) insolation and an ambient temperature of 24 C (75 F), which is appropriate for noon March 21 in Phoenix. Because of the small isolated nature of the load it was assumed that the control system for the solar system must be capable of following rapid load changes. It was also assumed that nighttime and cloudy day generation would be provided by the diesel generator.

A 1990 time frame was assumed for the Case 2 design. This time frame allowed the assumption of development of new materials and equipment, and sufficiently large production ranges to bring down capital costs on current non-commercial items.

10.2.1 System Description

The baseline system design for Case 2 has the following key characteristics; rationale for these design decisions are listed on Table 10.2-1.

TABLE 10.2-1. KEY DESIGN DECISIONS FOR CASE 2

Design Decision	Favoring Rationale	Opposing Rationale
Turbine inlet temperature (TIT) of 870 C (1,600 F).	• Higher TIT gives higher cycle efficiency. • Available Brayton engine is capable of 870 C (1,600 F) operation.[2] • Receiver can be built to operate at 870 C (1,600 F) assuming projected development of nitrogen dispersion strengthened steels.[3]	• Current receiver design is limited to 820 C (1,500 F) operation because of material limitations.[3]
Constant TIT turbine control, rather than constant speed control.	• Higher part load cycle efficiency. • Current developmental hardware uses this methodology.	• Variable speed control results in variable voltage generation.[2] • Availability/feasibility of appropriate voltage regulation hardware uncertain.[4]
Concentrator patterned after General Electric Low Cost Concentrator (LCC) [12 meter (39 feet) diameter].	• Brayton receiver and turbine currently being developed for use with LCC. • Concentrator able to provide design point power (11 meter dish being developed would not meet power requirement).[5]	• LCC reflective surface lifetime only 10 years.

TABLE 10.2-1 (Continued). KEY DESIGN DECISIONS FOR CASE 2

Design Decision	Favoring Rationale	Opposing Rationale
Rectification of ac generator output to dc for power collection. Subsequent inversion of power to ac.	• Avoids problems of synchronizing all turbines.	• Larger size cables required for transmitting low voltage (200 vdc) than for higher voltage ac.

- The hybrid OCB turbine and receiver are patterned after those currently being developed by Garrett Air Research Corporation.[2]
- A turbine inlet temperature (TIT) of 870 C (1,600 F) is utilized.
- A constant TIT turbine control, rather than constant speed control, is used.
- The field consists of twelve-meter (39 feet) diameter parabolic dish concentrators patterned after the General Electric Low Cost Concentrator.[5] The concentrators are arranged in a diamond pattern, with a 0.25 ground cover ratio occupying about 24 hectares (60 acres).
- Power generation by the OCB turbines is variable frequency ac, which is rectified for collection. Inversion back to ac takes place at nine locations within the field, with step-up transformers at each of these locations.

10.2.1.1 System Design Requirements. This subsection will present specific design requirements for the Case 2 baseline system. Topics addressed will include the following

- Site conditions,
- Site arrangement,
- System design point requirements,
- System functional requirements, and
- Standards and regulations.

Site Conditions. The Case 2 system is located at a site near Phoenix, Arizona. It is assumed for this study that the site selection can be made to minimize site preparation, and that plant support factors (roads etc.) are nearby. Table 10.2-2 lists the assumed Case 2 site conditions.

Site Arrangement. The physical layout for the Case 2 system is illustrated on Figure 10.2-1. The collector field, which covers about 24 hectares (60 acres), contains 510 collectors. The field is divided into nine electrical power collection modules, thereby reducing the length of the low voltage (200 v) direct current collection network with its attendant high cost/high power loss. These dc cables, as well as ac cables powering the concentrators, are direct buried along routes indicated on Figure 10.2-1. Inversion

TABLE 10.2-2. CASE 2 SITE CONDITIONS (Phoenix, Arizona)

Environmental Conditions[6,7]

- Maximum Temperature: 49 C (120 F).
- Minimum Temperature: -8 C (17 F).
- Annual Average Temperature: 21 C (70 F).
- Maximum Windspeed: 145 km/h (90 mph).
- Average Windspeed: 10 km/h (6.3 mph).
- Prevailing Wind Direction: East.
- Average Annual Precipitation: 18 centimeters (7.1 inches).
- Average Daily Direct Normal Insolation: 6.9 kWh/m^2/day (2,200 Btu/ft^2/day).

Assumed Terrain

- Relatively flat, level land area.
- Plant site has few, if any, trees.
- Competent bearing strata near surface.
- Seismic Zone: 2.

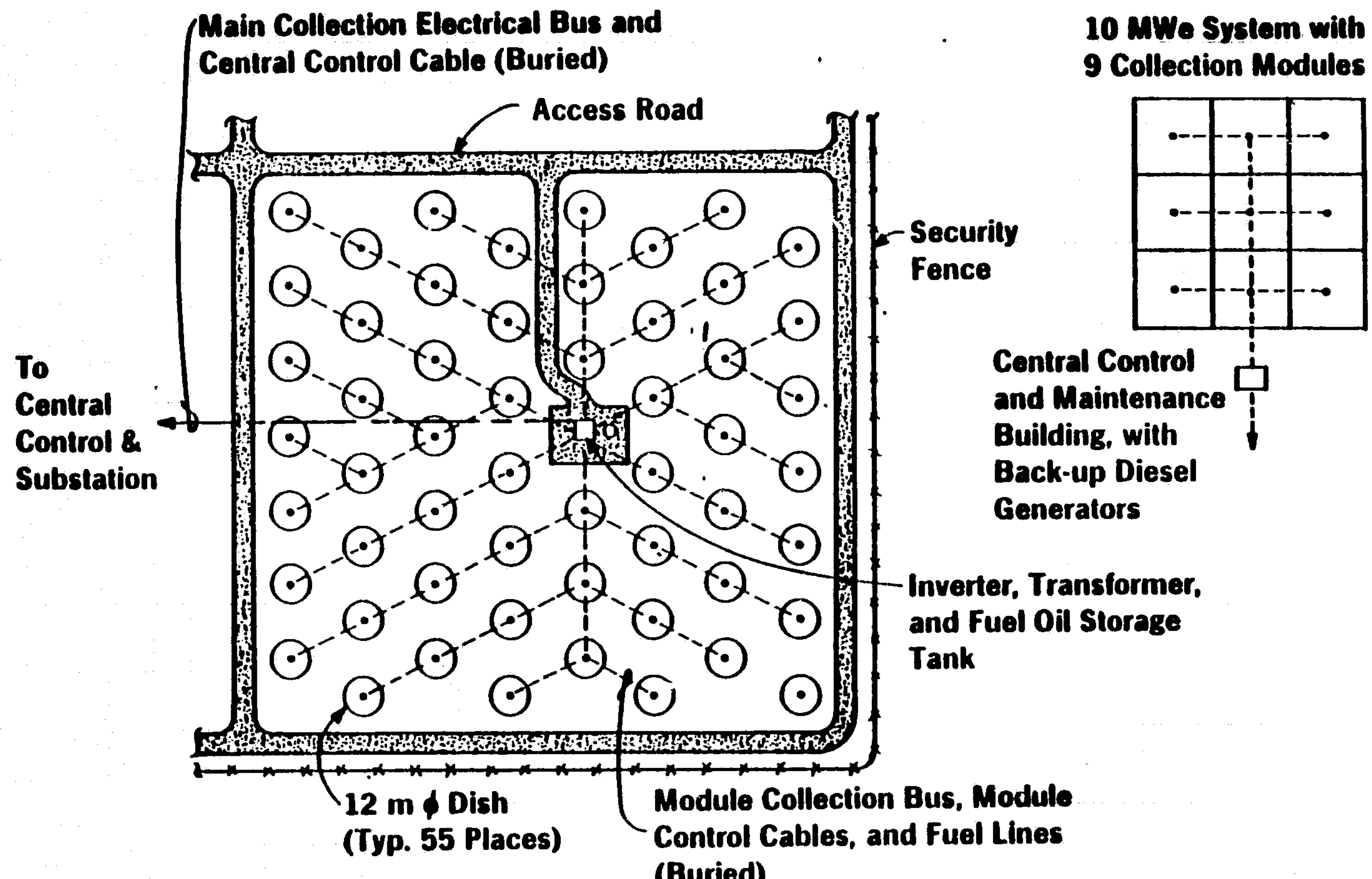

FIGURE 10.2-1 1.1 MWe OPEN BRAYTON CYCLE COLLECTION MODULE PLAN ARRANGEMENT

to ac and subsequent voltage step-up are accomplished at each of the nine central locations. A fuel tank [49,000 liters (13,000 gallons)] for the hybrid turbines is also located at each collection module center. Plastic fuel lines run to each collector. The tank was sized so as to typically require refilling on a monthly basis.

The central control facility as well as the maintenance shops are located in a building at the perimeter of the field; a warehouse for the spare parts inventory is located nearby. Also at the perimeter of the field are the four 2.5 MWe diesel generator units and the fuel storage tanks.

System Design Point Requirements. The baseline system for Case 2 was designed to provide rated power (10 MWe net) at noon March 21 using solar power only. A design point insolation of 950 watts/m^2 (301 Btu/hr/ft^2) was assumed. A functional flow diagram of a single collector and power conversion unit, giving temperatures, pressures, flow rates, and power values is shown on Figure 10.2-2. The series combustor, while shown on the diagram, does not provide power at the design time point since operation is totally from solar power conditioning equipment. Design details for the individual subsystems are listed on Table 10.2-3.

System Functional Requirements. Functional requirements for the system are addressed in this section, first in terms of system operating modes, and then the functional roles of the various subsystems to achieve those modes.

Operating modes for the system are placed in three categories.

- Steady state operation.
- Start-up of the solar system.
- Transients.

Steady state operation of the system will normally not utilize both the solar system and the diesel backup simultaneously. Because of the low part-load efficiency of the OCB, and because the fuel-to-electric conversion using the diesel back-up is more efficient than that of the OCB, the solar system will not be used to generate electricity when solar input is less than about 30 per cent of rated. This power input level is reached at about 6:45 am (solar time) on March 21, so minimal waste of solar energy occurs with this operating strategy.

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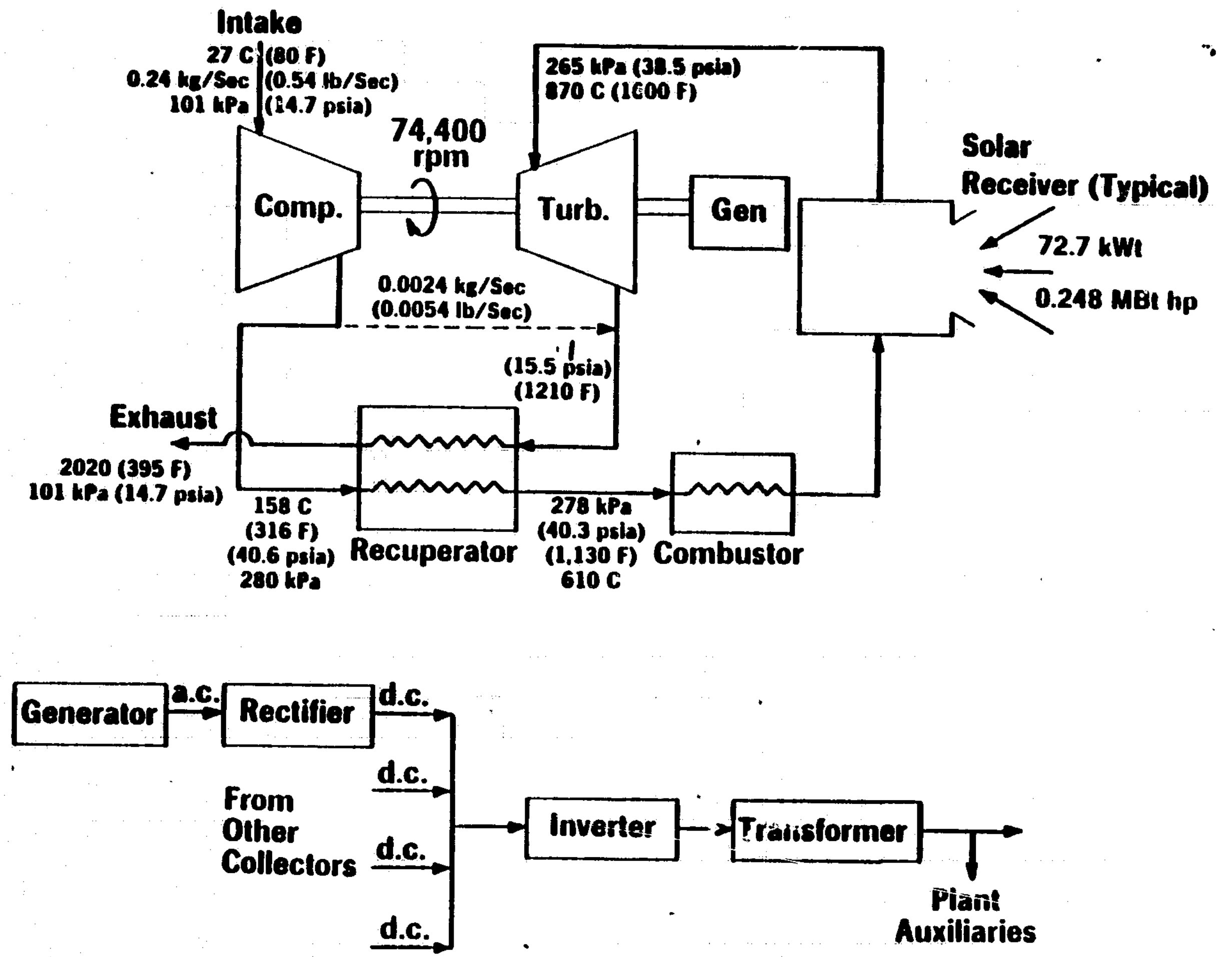

FIGURE 10.2-2 CASE 2 SYSTEM FUNCTIONAL FLOW DIAGRAM

TABLE 10.2-3. CASE 2 SUBSYSTEM DESIGN SUMMARIES

COLLECTOR SUBSYSTEM[5]

Parameter	D. P. Value*
Concentrator	
Dish Diameter, m (ft)	12 (39)
Effective Aperture Area, m^2 (ft^2)	111 (1,190)
Reflectivity	0.84
Shading Factor	0.94
Intercept Factor	0.96
Concentrator Effectiveness	0.74
Brayton Receiver	
Outer Diameter, m (ft)	0.76 (2.5 ft)
Aperture Diameter, m (ft)	0.25 (0.82 ft)
Inlet Temperature, C (F)	610 C (1,130)
Outlet Temperature, C (F)	870 C (1,600)
Power Input, kWt (MBtu/h)	79.9 (0.273)
Power Output, kWt (MBtu/h)	72.7 (0.248)
Efficiency	0.91
Pressure Drop, kPa (psig)	(0.7)
Air Flow Rate, kg/sec (lbm/sec)	(0.56)

*Design point value.

Note: Receiver capability to operate at 870 C (1,600 F) dependent on commercial availability of nitrogen dispersion strengthened steel.[3]

ELECTRICAL ENERGY TRANSPORT SUBSYSTEM

Parameter	D. P. Value*
Thermal Input, kWt (MBtu/h)	72.7 (0.248)
Cycle Efficiency	0.330
Shaft Output Power, kWm (hp)	24.05 (32.26)
Compressor Inlet Temperature, C (F)	21 (70)
Compressor Inlet Pressure, kPa (psia)	101 kPa (14.7)
Turbine Inlet Temperature,** C (F)	870 (1,600)
Shaft Speed, rpm	74,400
Compressor Compression Ratio	2.76
Turbine Expansion Ratio	2.48
Recuperator Effectiveness	0.92
Bleed Flow Fraction	0.01
Generator Efficiency	0.94
Rectifier Efficiency	0.96
Gross Electric Power, kWe (dc at rectifier)	21.7
Electric Accessory Load, kWe	0.299
Module Electric Power, kWe (dc)	21.4
Recuperator H.P. Inlet Temperature, C (F) (Compressor Outlet Temperature)	158 (316)
Recuperator H.P. Outlet Temperature, C (F) (Receiver Inlet Temperature)	610 (1,130)
Recuperator L.P. Inlet Temperature, C (F) (Turbine Exhaust Temperature)	654 (1,210)
Recuperator L.P. Outlet Temperature, C (F) (Exhaust Temperature)	202 (395)
Flow Rate, kg/sec (lb/sec)	0.2465 (0.5434)

*Design point value.

**Turbine inlet temperature is maintained at 870 C (1,600 F) at part load; shaft speed is appropriately altered.

ELECTRICAL ENERGY TRANSPORT SUBSYSTEM

- General electrical layout as per Figure 10.2-1.
- Collection of 200 vdc at 9 central locations.
- Buried cable with EPR or XLPE insulation (as appropriate) and CSP Jacket.
- Nine 1,500 kVA solid state static inverters.
  - -- 200 vdc to three phase 480 vac.
  - -- 0.94 efficiency at rated load.
  - -- Automatic synchronization with line signal.
- Nine 1,500 kVA, 4,160 V/480 V transformers with outdoor enclosure.
- Switchgear and lighting protection.

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MASTER CONTROL SUBSYSTEM

- Central Control Mini-computer.
- Main Control Panel.
- Programmers Console.
- CRT Displays.
- Printer.
- Interface Hardware.
  - -- Turbine Controllers.
  - -- Collector Controllers.
  - -- Energy Transport Controllers.
  - -- System Instrumentation.

DIESEL-GENERATOR BACKUP SYSTEM

- Four 2,500 kW fast-start diesel generators.
- 473,000 liter (125,000 gallon) fuel tank with oil containment berm.

BALANCE OF PLANT

- Buildings.
  - -- Central Control and Maintenance.
  - -- Warehouse (spare parts inventory).
- Maintenance Equipment.
  - -- Truck.
  - -- Crane.
  - -- Washing Vehicle.
  - -- Tools.
- Fire Protection System.
- Plant Lighting System.
- Roads.
- Security Fence.

When solar power input is above 30 per cent of its rated value, the solar system will normally be used to generate electricity. If the load is greater than solar power capability, hybrid operation with fossil fuel will be utilized. If the load is less than the solar power capability, an appropriate number of concentrators will be defocused. Therefore steady state operation can be summarized as follows.

- Solar input less than 30 per cent: use diesel.
- Solar input greater than 30 per cent, but less than the load: utilize fossil/solar hybrid.
- Solar input greater than 30 per cent, and greater than the load: utilize solar only, defocus some concentrators.

Transients in the solar operation will come about because of changes in solar power and changes in the load. Both occurrences require rapid adjustment of the system, and essentially constitute difficult control problems. It is assumed that the solar system (along with diesel backup) constitutes a major, if not the sole, source of electrical power to the installation, and therefore, must be capable of uninterrupted, load following power generation. The goal of the system control in handling transients is to not only respond rapidly, but also to respond intelligently in terms of conserving fuel. Possible control logic to achieve the latter goal will be addressed under control subsystem requirements.

Start-up of the solar system requires heat-up of the receiver, starting of the compressor, and heat-up of the turbine and recuperator. The compressor will be started by using the permanent magnet generator as a motor.[2] Because of the uncertain nature of solar insolation, the turbine will be started using fossil energy. The timing of this start-up must correlate with expected solar levels so that premature or late start-up times are avoided, as they waste fuel and solar energy. Start-up and shutdown are the only times where the solar system and diesel back-up will run simultaneously.

In achieving the above system operating modes, the <u>Collector Subsystem</u> must fulfill the following functional requirements.

- Two axis tracking of the sun.
- Heat air from 613 C (1,135 F) (or higher if the combustor is used) to 870 C (1,600 F).
- Deliver up to 72.7 kW_t (0.248 MBtu/hr) to the OC turbine.
- Operate in winds up to 50 km/hr (31 mph).
- Slew to stow in winds up to 80 km/hr (50 mph).
- Survive stowed in winds up to 120 km/hr (75 mph).
- Survive 1/4 g lateral seismic load.

The Power Conversion Unit, including the turbine, generator (with rectifier), recuperator, compressor, and combustor must fulfill the following functional requirements.

- Generate up to 21.7 kW_e dc per dish unit.
- Respond rapidly as per control system command to increase or decrease fuel consumption.

The Energy Transport system must fulfill the following functional requirements.

- Collect up to 1.2 MWe at 200V dc at each collection center.
- Invert dc to three phase ac at 480 volts.
- Step up to 4,160 volts ~~ac~~ for transmission to the overall system output bus.
- Provide switching for isolation of collector modules and individual collectors.
- Provide lighting protection.

The Master Control System must fulfill the following functional requirements.

- Send command signals to individual collectors to track, defocus, or stow.
- Coordinate solar system start-up.
  - -- Initiate turning of turbine/compressor via starting motor.
  - -- Power the turbine with fossil fuel.
  - -- Commence tracking of the sun when turbine start-up has been initiated.

-- Switch from diesel backup as solar/fossil hybrid reaches power threshold.

- Coordinate solar system shutdown.
  -- Cease tracking of sun.
  -- Switch to diesel backup.
  -- Cease fossil power to turbines.
- Match power generation to load.
  -- Maximizing use of solar power.
  -- Detect changes in load.
  -- For increase of load, add collectors if some are defocused; if not, increase fuel consumption.
  -- For decrease of load, reduce fuel consumption if all collectors are tracking; if not, defocus additional collectors.
- Provide warnings and alarms for faulty operation.

Standards and Regulations. The Case 2 system design is responsive to a number of laws, ordinances, codes, and standards. Table 10.2-4 lists applicable regulations, along with the more significant impacts of those regulations.

10.2.1.2 Operational Characteristics. Four areas of operational characteristics for the Case 2 System have been identified. These topics are as follow.

- Personnel
- Consumables
- Maintenance
- Safety

An operating and maintenance staff of five people is anticipated. This staff would include three plant operators with duty hours arranged so as to cover the average system operation 12 hours per day, 7 days per week. Each day two operators shifts would coincide during a part of that day. During those times, as well as on cloudy days, operators would perform inspections and routine maintenance. The other workers would perform maintenance duties full time.

TABLE 10.2-4. APPLICABLE STANDARDS AND REGULATIONS

Requirement	Major Impact
Federal Laws and Ordinances Fuel Use Act Clean Air Act Noise Control Act National Environmental Policy Act Federal Water Pollution Control Act	Prevention of fuel leaks. Containment by the berm if leaks from the large tank occurs.
OSHA Codes and Standards Occupational Safety and Health Standards Safety and Health Regulations	Design and safety procedures must guard against electrical hazards and burns, thermal burns, eye damage from concentrators, and affliction from toxic substances.
Association Codes and Standards—(NFPA, ANSI, ASME, NEMA) National Electric Code Line Safety Code Boiler and Pressure Vessel Code	Fire protection around fuel systems Specification of electrical hardware.

Consumables for the system will be primarily fuel and concentration washing solution. The fuel consumed depends upon system load; a determination of projected fuel usage has not been conducted in Task 10. Washing solution consumption is estimated to be about 49,000 liters (13,000 gallons) per month; the solution makeup is primarily water. Other system consumables are low quantity.

The primary maintenance activity will be washing of concentrators. Using a special washing vehicle, the monthly washing process is anticipated to take about 15 minutes per concentrator, adding up to about 16 man-days per month. Other routine maintenance activities will include annual inspections of electrical equipment (switchgear, tranformer oil level, etc), concentrator reflective surfaces, etc.

Projected equipment overhaul includes refurbishing of concentrator reflector surfaces after about 10 years of service.[4] It is anticipated that gore panels would be replaced with new or refurbished panels, and that the old panels would be returned to the manufacturer. This process could be staggered over a long period of time such that plant output would not be significantly impacted. Likewise, scheduled overhaul of Brayton engines would be staggered such that only a few dishes would be inoperable at any given time.

Unscheduled maintenance will primarily involve concentrator tracking mechanisms. An inventory of spare parts will be maintained.

Safety considerations for the Case 2 System are as follows.

- Fire protection, particularly around fuel tanks and fuel lines.
- High voltage electrical system.
- Burns or eye damage from concentrators. This, in general, should not be a problem since the danger is primarily at the focal point of the concentrator. Safety procedures must be developed which assure that personnel will not be in a danger zone while concentrators are tracking.

10.2.2 System Construction Considerations

A schedule for the design, procurement, and construction of the Case 2 System is shown on Figure 10.2-3. Total elapsed time from initiation of preliminary specifications to initial plant operation is 24 months.

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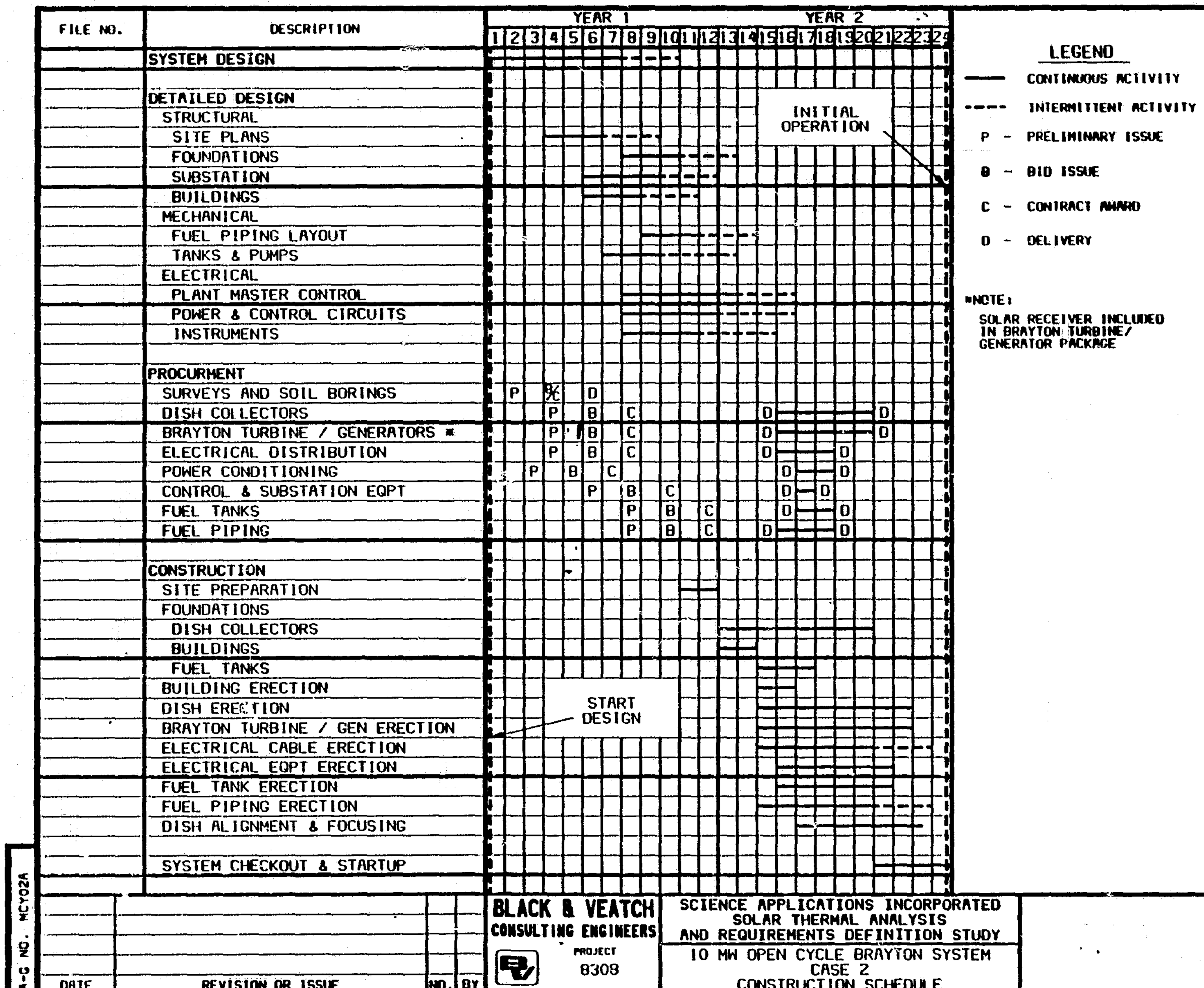

FIGURE 10.2-3 CASE 2 SYSTEM CONSTRUCTION SCHEDULE

Key assumptions used in preparing the schedule are as follows.

- A peak work force of about 100 men is anticipated, with a wide range of skill levels.
- An 8-hour day/20-day work month is assumed.
- Four 4-man crews assemble 12 dish/turbine/generator units per week.(8)
- Foundations for dishes are drilled and poured at 1-1/2 per day.
- Electrical cabling connecting collectors is buried during early stages of construction. Electrical connections are made as dishes are erected.

10.2.3 System Cost Estimates

A determination of Case 2 capital and O&M costs has been made; a summary of those costs, broken down by subsystems, is presented in Table 10.2-5. It can be seen that the collector subsystem constitutes a large share of the overall system cost (about 50 per cent), with the electric power generation and electrical energy transport subsystems contributing smaller, nearly equal costs. Key assumptions in the cost determination were as follows.

- Collector, receiver, and power conversion unit material costs (\$100/m^2, \$60/kWe and \$250/kWe) are in agreement with the Task I data base (6) and with DOE cost goals.(9)
- Electrical energy transport subsystem costs were based on a material take-off generated for Case 2.
- An inverter cost of \$75/kWe was assumed.(10)

10.2.4 Case 2 References

1. Science Applications, Incorporated Solar Thermal Plant Impact Analysis and Requirements Definition Study, Task 5-8 Preliminary Case Study Report, JPL Contract No. 955238, June 26, 1980.
2. L. D. Six and others, Concept Definition Study of Small Brayton Cycle Engines for Dispersed Solar Electric Power Systems, DOE/NASA/0069-79/1, January 1980.
3. Private communication to L. E. Stoddard, Black & Veatch, from Max Greeven, Project Engineer, AiResearch Manufacturing Company of California, August 25, 1980.
4. Private communication to L. E. Stoddard, Black & Veatch, from Jeff Zimmerman, General Electric, August 29, 1980.

TABLE 10.2-5. CASE 2 COST SUMMARY

Item	Capital Cost* $1,000	
Land		150
Site Preparation		90
Collector Field		8,931
Concentrators	5,800	
Receivers	660	
Concentrator/Receiver Installation	1,639	
Foundations (Installed)	832	
Electric Power Generation		3,960
Turbine/Generator	2,750	
Turbine Generator Installation	667	
Fuel System	264	
Fuel System Installation	279	
Electric Energy Transport		2,513
Power Distribution	589	
Power Conditioning	750	
Installation	1,174	
Master Control		1,750
Balance of Plant		332
Subtotal		17,726
Contingencies (15 per cent)		2,659
Total Direct Costs		20,385
Indirects (25 per cent)		5,096
Total		25,481

Operations and Maintenance Cost: $382,000/year

*Diesel Backup Package Capital Cost is $4,179,000.

5. Jet Propulsion Laboratory, Proceedings of the First Semi-Annual Distributed Receiver Systems Program Review, DOE/JPL-1060-33, April 15, 1980.

6. Science Applications, Incorporated, Solar Thermal Plant Impact Analysis and Requirements Definition Study, Summary Report for Tasks 1, 2, and 3, JPL Contract No. 955238, September 7, 1979.

7. "Local Climatological Data, 1978, Phoenix, Arizona," National Climatic Center, Ashville, North Carolina.

8. Private communication to L. E. Stoddard, Black & Veatch, from Jeff Zimmerman, General Electric, September 8, 1980.

9. Private communication to L. E. Stoddard, Black & Veatch, from John Lucas, Jet Propulsion Laboratory, August 4, 1980.

10. Private communication to L. E. Stoddard, Black & Veatch, from R. Rosati, United Technologies Corporation, September 12, 1980.

10.3 CASE 3: LARGE INVESTOR-OWNED UTILITY--9 MWe

Case 3 is defined to be a 9 MWe parabolic dish system located near Phoenix, Arizona, as a part of a large investor-owned utility. Distinguishing features of the case definition are as follows:

- General Electric Low Cost Concentrator,
- Central generation via nine 1 MWe modules, each with an organic Rankine cycle turbine,
- Five hours of thermal storage,
- Thermal energy transport via an oil (as opposed to liquid sodium, used in Case 1, or molten salts), and
- A sensitivity study which replaces nine 1-MWe turbines and their electrical interconnection with a single 9 MWe turbine and an expanded thermal energy transport system.

The design of the system is based on a 1990 time frame. This lead time allows extrapolation of current technological developments as well as reduction of key component costs to a "mature" level.

The system is configured for a noon, March 21 design point, with an assumed insolation level of 950 watts/m^2 (301 Btu/hr/ft^2). By designing the system for a typical clear day, noon peak insolation, the system capability to handle peak solar power inputs is assured. As in the Case 1 design, the collector system is sized so as to just fill the five-hour thermal storage on a clear March 21.

10.3.1 System Description

The primary design decision for Case 3 has been the selection of the receiver working fluid. Silicone oils (typified by Dow Syltherm 800) are capable of operation up to (and above, if pressurized) 390 C (750 F), but are expensive (~$20 per gallon). Organic oils (typified by Exxon Caloria HT-43) are less expensive (~$1.50 per gallon), but are less stable and allow operation only up to about 316 C (600 F); as a result, cycle efficiencies are lower, requiring larger collector fields, piping networks, etc.

While a detailed trade study is beyond the scope of this design effort, a first level comparison of system cost/performance considerations for

Syltherm versus Caloria HT-43 has been conducted. This comparison resulted in the selection of Syltherm as the heat transfer fluid, with storage via a "trickle oil" system; the comparison is documented in Table 10.3-1.

The Case 3 thermal storage is patterned after the trickle oil storage of the Shenendoah Solar Total Energy Project.[2] This storage concept minimizes the necessary inventory of expensive Syltherm. The Syltherm acts only as the heat transfer medium; thermal storage capacity is provided by a solid storage media in a packed bed form. The Shenendoah project design utilizes taconite as the solid media. The Case 3 design uses crushed, recycled glass as per a SERI modification of the Shenendoah concept.[3,4]

The trickle oil system consists of four storage tanks, with interconnecting piping, pumps, and valves. Multiple tanks are required to allow discharge of a partially charged system. One tank is sized to provide about an hour of rated turbine operation; this tank would normally be charged early in the day to provide buffer storage during intermittent cloud coverage. The remaining three tanks would be charged sequentially throughout the day to provide turbine operation during non-daylight hours.

Because of high piping costs for systems requiring alloy steel (as evidenced in Case 1), a receiver outlet temperature of 390 C (750 F) was selected. This maximum fluid temperature allows the use of carbon steel pipe for both the supply and return pipelines. The Syltherm temperature when storage is discharged is 376 C (725 F), slightly lower than the receiver outlet temperature. This results in a slight degradation of turbine cycle efficiency when operating from storage.

10.3.1.1 <u>System Design Requirements</u>. This subsection presents specific design requirements for the Case 3 system. Topics addressed include the following.

- Site conditions,
- Site arrangement,
- System design point requirements,
- System functional requirements, and
- Standards and regulations.

TABLE 10.3-1. HEAT TRANSFER FLUID COMPARISON FOR CASE 3 [1,2,3,4,16,17]

Factor	Syltherm 800; at 390 C (750 F)	Caloria HT-43; at 316 C (600 F)
Cycle Efficiency	Base	Decrease by ~25 per cent
Fluid Cost	~\$20/gallon	~\$1.50/gallon
Fluid Replacement	30-40 per cent per year. May be significantly reduced by pressurizing system to 140 kPa (20 psi).	25-35 per cent annually
Degradation	Volatiles	Volatiles and Solids (Increased Fluid Maintenance)
System Cost	Trickle oil storage system, including fluid in piping network: \$8,062,000 Remainder of system: Base Total cost: \$8,062,000 plus base	Thermocline storage system including fluid in piping network: \$3,600,000 Remainder of system - Piping: \$2,174,000 plus base - Collector: \$2,100,000 plus base - Electrical: \$600,000 plus base - Other: \$105,000 plus base Total cost: \$8,579,000 plus base

Site Conditions. The site for the Case 3 system is in the vicinity of Phoenix, Arizona. It is assumed that the site selection can be made to minimize site preparation, erecting of electrical transmission lines, and other plant support items such as access roads. Table 10.3-2 lists the assumed site conditions.

Site Arrangement. The physical arrangement for the Case 3 system is shown on Figure 10.3-1. The layout of each module is similar to that of the Case 1 system except for a larger number of collectors per module (84 for Case 3 versus 78 for Case 1). An additional change is a small reduction of some pipe sizes. As in Case 1, the turbines have been placed at the collector field perimeter, with cooling towers further outside to minimize the effects of the cooling tower plume on the field. The inset of Figure 10.3-1 shows the overall arrangement of modules; for the odd number of modules of Case 3, the central control building and maintenance area are located in the "empty" land area.

System Design Point Requirements. The system is designed to provide rated power (9 MWe gross, 8.4 MWe net) at noon March 21. Figure 10.3-2 shows the functional configuration of the system as well as identifying design point temperatures, pressures, flow rates, and power traces. Design details for the individual subsystems are listed on Table 10.3-3.

System Functional Requirements. The previous section on system design point characteristics has described the Case 3 system configuration as well as design point temperatures, flow rates, and powers. This section identifies various system operating modes and the functional roles of the various subsystems in achieving those modes.

The overall system has been designed for a rated gross power of 9.0 MWe resulting in a net power output of 8.4 MWe. System operating modes are identical to those discussed for Case 1 in Subsection 10.1.1.1 under System Functional Requirements. A brief recapitulation of that discussion and its corresponding graphic, Figure 10.1-3, are included here for the reader's convenience.

TABLE 10.3-2. CASE 3 SITE CONDITIONS (Phoenix, Arizona)

Environmental Conditions[5,6]

- Maximum Temperature: 49 C (120 F).
- Minimum Temperature: -8 C (17 F).
- Annual Average Temperature: 21 C (70 F).
- Maximum Windspeed: 145 km/h (90 mph).
- Average Windspeed: 10 km/h (6.3 mph).
- Prevailing Wind Direction: East.
- Average Annual Precipitation: 18 centimeters (7.1 inches).
- Average Daily Direct Normal Insolation: 6.9 kWh/m^2/day (2,200 Btu/ft^2/day).
- Sufficient water is available for use of a wet cooling tower.

Assumed Terrain

- Relatively flat, level land area.
- Plant site has few, if any, trees.
- Competent bearing strata near surface.
- Seismic Zone: 2.

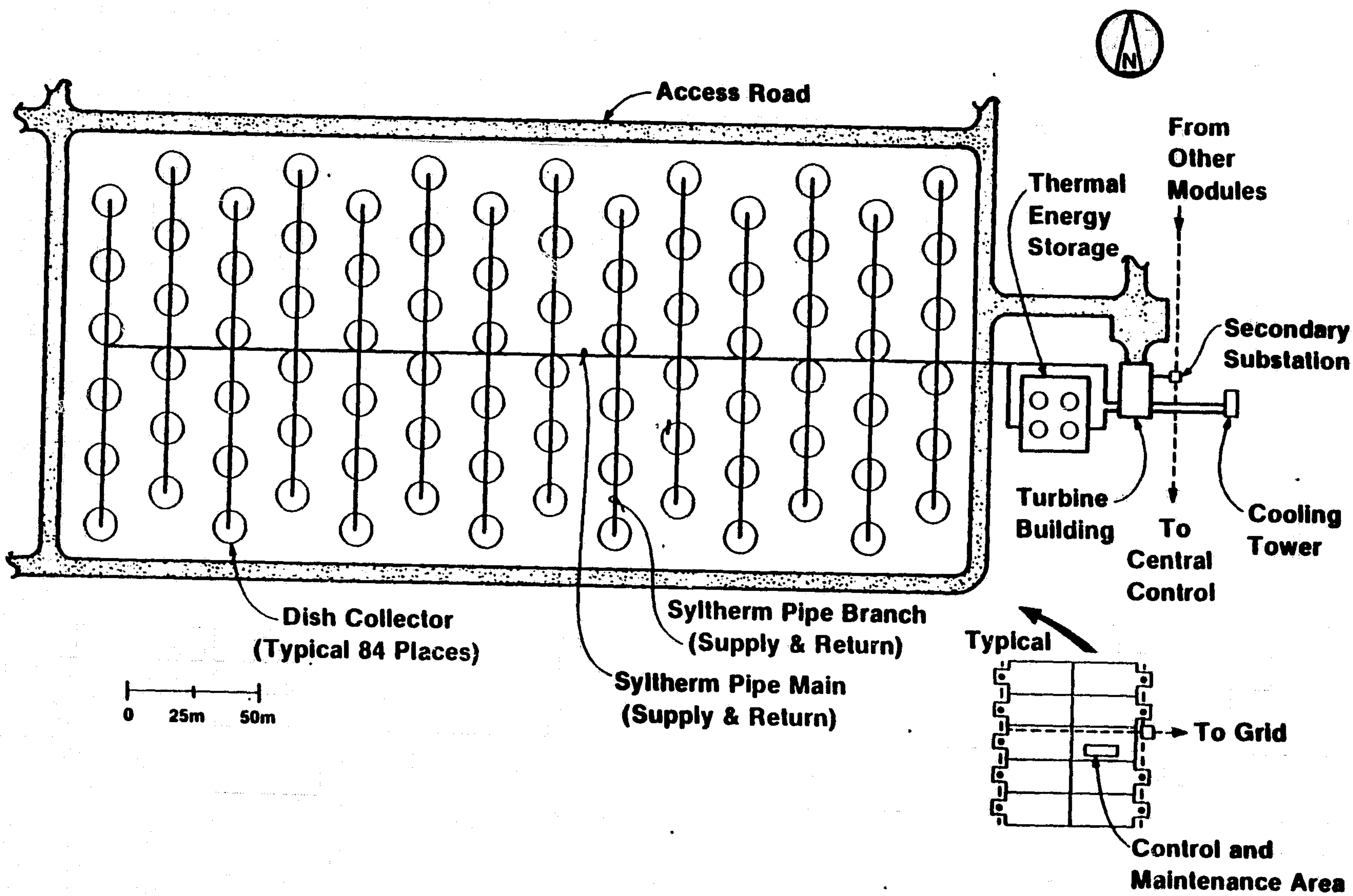

FIGURE 10.3-1 1MWe ORGANIC RANKINE CYCLE COLLECTION MODULE PLAN ARRANGEMENT

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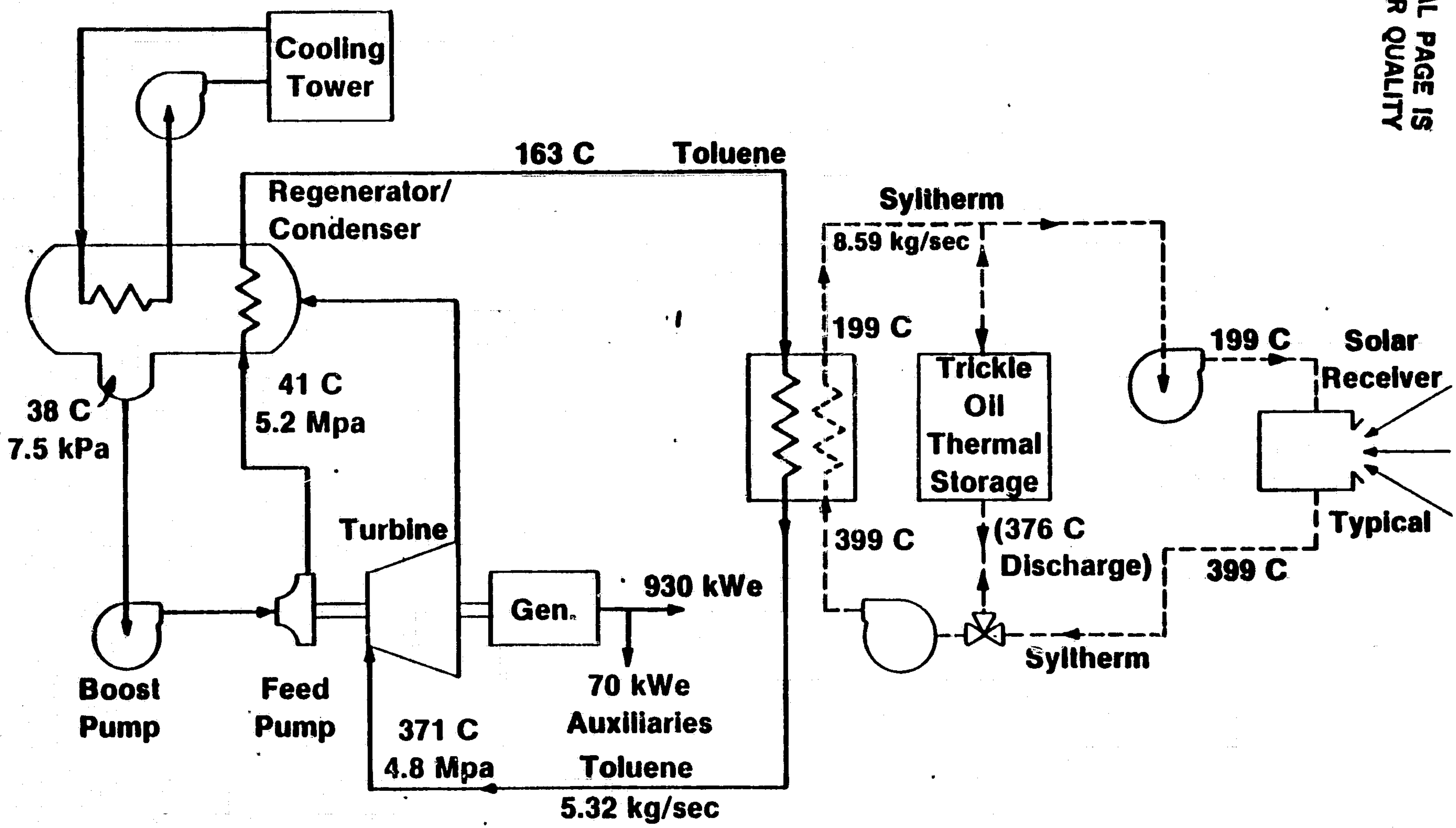

FIGURE 10.3-2 FUNCTIONAL FLOW DIAGRAM FOR CASE 3 SYSTEM

TABLE 10.3-3. CASE 3 SUBSYSTEM DESIGN SUMMARIES

COLLECTOR SUBSYSTEM

Parameter	D. P. Value*
Concentrator[7]	
Dish Diameter, m (ft)	12 (39)
Effective Aperture Area, m^2 (ft^2)	111 (1,190)
Reflectivity	.84
Shading Factor	.94
Intercept Factor	.96
Concentrator Effectiveness	.74
Weight, kg (lb)	5,900 (13,000)
Receiver	
Outer Diameter, m (ft)	0.75 (2.5)
Aperture Diameter, m (ft)	0.25 (0.8)
Weight, kg (lb)	227 (500)
Inlet Temperature, C (F)	199 (390)
Outlet Temperature, C (F)	399 (750)
Power into aperture, kWt (MBtu/h)	79.9 (0.273)
Power to fluid, kWt (MBtu/h)	77.1 (0.263)
Mass Flow, kg/sec (lbm/sec)	0.19 (0.41)
Efficiency	0.965
Radiation Losses, kWt (Btu/h)	0.7 (2,400)
Convection Losses, kWt (Btu/h)	1.4 (4,800)
Conduction Losses, kWt (Btu/h)	0.7 (2,400)

*Design point.

ELECTRIC POWER GENERATION SUBSYSTEM[8,9]

Parameter	D. P. Value[a]
Cycle	Supercritical ORC
Working Fluid	Toluene
Turbine Type	Single-Stage Impulse
Thermal Input, kWt (MBtu/h)	3,520 (12.01)
Cycle Efficiency[b]	0.296
Shaft Output Power, kWm (hp)	1,042 (1,397)
Turbine Inlet Temperature, C (F)	371 (700)
Turbine Inlet Pressure, MPa (psia)	4.8 (700)
Condensate Temperature, C (F)	38 (100)
Regenerator Effectiveness	0.65
Shaft Speed, rpm	12,000
Generator Efficiency	0.96
Gross Electric Output, kWe	1,000
Electric Auxiliary Load,[c] kWe	70
Net Electric Output, kWe	930
Boiler Toluene Inlet Temperature, C (F)	163 (325)
Boiler Toluene Outlet Temperature, C (F)	371 (700)
Boiler Syltherm Inlet Temperature, C (F)	399 (750)
Boiler Syltherm Outlet Temperature, C (F)	199 (390)
Toluene Flow Rate, kg/sec (lb/sec)	5.32 (11.7)
Syltherm Flow Rate, kg/sec (lb/sec)	8.59 (18.9)

[a]Design point.
[b]The cycle efficiency is reduced to 0.290 when operating from storage.
[c]Total module-related auxiliary power requirements.

MASTER CONTROL SUBSYSTEM

- Central Control Mini-computer.
- Main Control Panel.
- Programmers Console.
- CRT Displays.
- Printer.
- Interface Hardware.
  -- Turbine Controllers.
  -- Collector Controllers.
  -- Energy Transport Controllers.
  -- System Instrumentation.

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THERMAL ENERGY STORAGE SUBSYSTEM[2,3,4]

Parameter (Per Module)	Value
Configuration	Trickle Oil
Medium	Syltherm 800 and Crushed Glass
Capacity, MWht (MBtu); hours	17.6 (60.1); 5
Charge Temperature, C (F)	399 (750)
Discharge Temperature, C (F)	385 (725)
Syltherm Inventory**, kg (lbs)	13,600 (30,000)

THERMAL ENERGY TRANSPORT SUBSYSTEM

- General piping layout as per Figure 10.3-1.
- Detailed piping layout similar in nature to Shenendoah Solar Total Energy Project piping layout.[2]
- All piping, valves, and fittings of A106 Carbon Steel.
- Insulated to reduce thermal losses to 5 per cent of rated power.
- Pressure drop less than 138 kPa (20 psid).
- All joints welded.

BALANCE OF PLANT

- Buildings.
  -- Turbine (9).
  -- Central Control and Maintenance.
  -- Warehouse (spare parts inventory).
- Maintenance Equipment.
  -- Truck.
  -- Crane.
  -- Washing Vehicle.
  -- Tools.
- Fire Protection System.
- Plant Lighting System.
- Roads.
- Security Fence.

Sizing of the storage system was conducted so that the system could be operated on a clear March 21 as shown on Figure 10.3-3a. A more likely operating strategy would be as shown on Figure 10.3-3b. Operation on typical clear summer and winter days is depicted in Figures 10.3-3c and 10.3-3d. On summer days the energy to the field may be sufficiently large so as to require defocusing due to filled storage; on winter days storage may not be filled completely. Figure 10.3-3e shows operation of the system during a day with intermittent cloud cover.

Individual subsystems have been designed to meet the overall system functional requirements. The remainder of this section will address subsystem functional requirements.

In achieving the above system operating modes, the Collector Subsystem must fulfill the following functional requirements.

- Two-axis tracking of the sun.
- Heat Syltherm from 199 C to 399 C (390 F to 750 F).
- Deliver up to 77.1 kWt (263,000 Btu/hr) per collector to the Syltherm.
- Operate in winds up to 50 km/hr (31 mph).
- Slew to stow in winds up to 80 km/hr (50 mph).
- Survive in stowed position for winds up to 145 km/hr (90 mph).
- Survive 1/4-g lateral seismic load.

The Energy Transport System, which for this case involves the movement of both thermal and electrical energy, must fulfill the following functional requirements.

- Transport Syltherm to and from the collectors with thermal losses not to exceed 2,900 kWt (9.9 MBtu/hr) (5 per cent at the design point).
- Prevent Syltherm leaks.
- Provide for automatic isolation of piping serving the nine collector branches, and manual isolation of individual collectors to facilitate safety, reliability, and maintenance.
- Withstand 1/4-g lateral seismic load.
- Provide for a pressure drop not to exceed 20 psig at rated flow.

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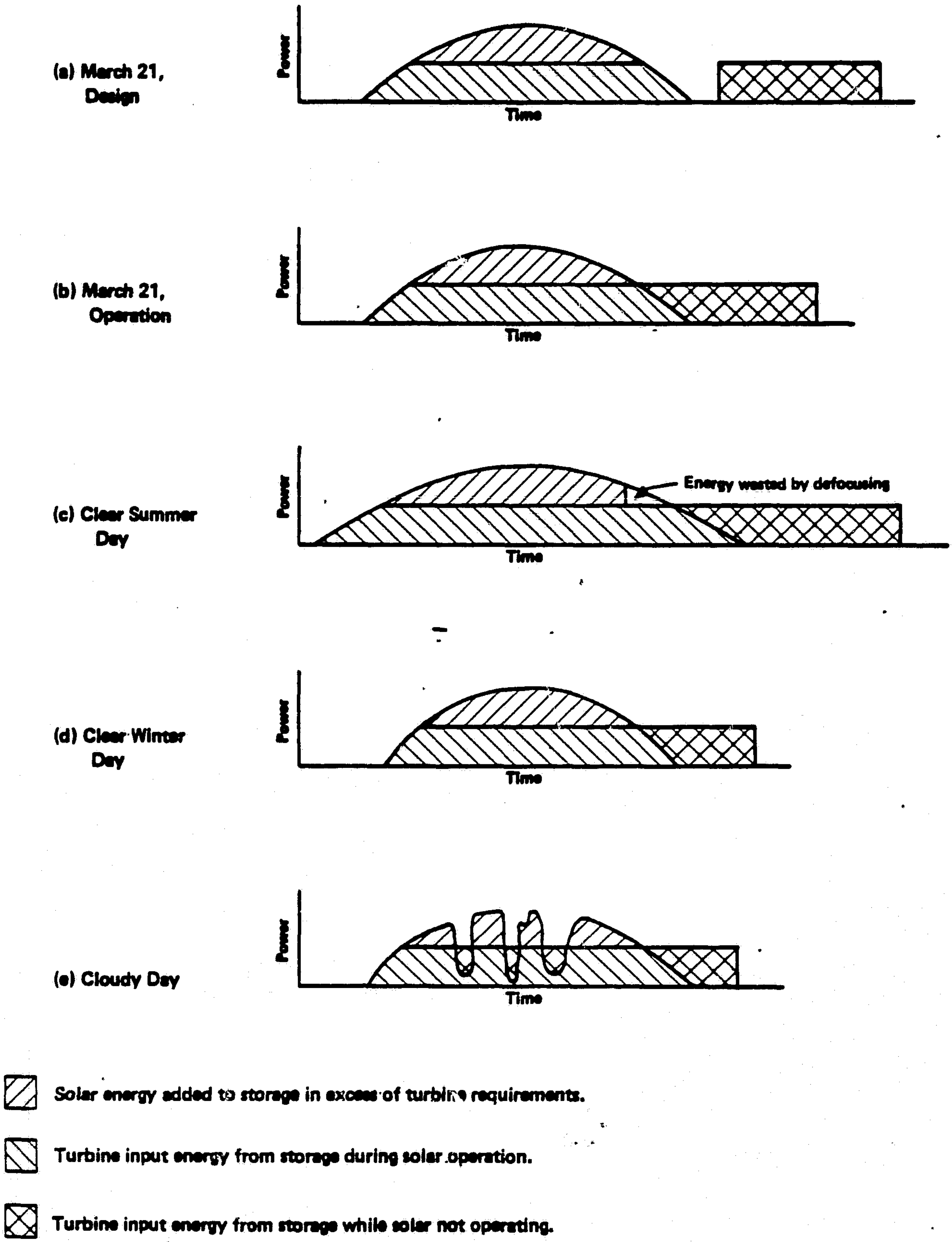

FIGURE 10.3-3 CASE 3 OPERATING MODES

The Thermal Storage Subsystem must fulfill the following requirements.

- Provide storage capacity to allow thermal input to the turbines for 5 hours operation at a slightly derated power.
- Accept charge rates from 350 kWt to 7,000 kWt per module.
- Provide discharge rates from 180 kWt to 3,600 kWt per module.
- Maintain Syltherm quality and subsystem integrity.
- Provide for thermal losses to be less than 1 per cent of design point capacity per hour.

The Electric Power Generation Subsystem has the following functional requirements.

- Transfer heat from Syltherm at 399 C (750 F) to toluene with an exit temperature of 371 C (750 F) at rates up to 3,600 kWt per module.
- Generate up to a gross power of 9 MWe (nine modules).

The Central Control System must fulfill the following functional requirements.

- Allow dispatcher control of turbine output power.
- Send command signals to individual collectors to track, "defocus", or stow.
- Monitor energy in thermal storage.
  - "Defocus" an appropriate number of collectors when storage is filled to capacity and the turbine is operating at rated power.
  - Command all collectors to track the sun when the system can utilize the full output of the collector system.
- Monitor system temperatures, pressures, and flows.
- Provide warnings and alarms for faulty operation.
  - High temperatures and pressures.
  - Indications of leaks.
- Provide built-in automatic system start-up and shut-down algorithms for the collector field. The start-up algorithm must assure that thermal storage is not thermally degraded by premature circulation of Syltherm through the collector field.

Standards and Regulations. The Case 3 system design is responsive to a number of laws, ordinances, codes, and standards. Table 10.3-4 lists applicable regulations, along with the more significant impacts of those regulations.

10.3.1.2 Operational Requirements. The day-to-day operational factors of the Case 3 system consists of four elements.

- Personnel
- Consumables
- Maintenance
- Safety

Operations and maintenance personnel required to staff the plant include five full time workers. Three of these workers are plant operators; duty hours are structured so as to cover average system operation 17 hours per day, 7 days per week. During cloudy days, operators perform routine inspections and maintenance tasks. The remaining workers are assigned full time to maintenance tasks, the chief task being washing of the collectors. No allocation of administrative personnel has been made.

The primary consumable for the system is collector washing fluid. A wash and rinse method is proposed, with a total water usage of 70,000 liters (19,000 gallons) per month [the basis is 95 liters (25 gallons) per wash per concentrator, and monthly washing]. Other consumables are low in quantity; lubricants, toluene make-up [per turbine, 8 liters (2 gallons) per week, plus 3,800 liters (1,000 gallons) at each 5 year turbine overhaul], nitrogen to provide a protective blanket for the Syltherm, and Syltherm make-up.

The primary maintenance activity will be the washing of concentrators. A washing vehicle which washes and then rinses the concentrator will be used. It is estimated that the cleaning process, which will be conducted once each month, will take 15 minutes per concentrator; this amounts to about 24 man-days per month. Other routine maintenance tasks will include inspection of system conponents for malfunctions (e.g., piping network for evidence of leaks; collectors for tracking problems). Scheduled maintenance for valves includes annual inspection, packing, and calibration of control

TABLE 10.3-4. APPLICABLE STANDARDS AND REGULATIONS

Requirement	Major Impact
Federal Laws and Ordinances Clean Air Act Noise Control Act National Environmental Policy Act Federal Water Pollution Control Act Toxic Substance Control Act	Design must protect against toluene and Syltherm leaks.
OSHA Codes and Standards Occupational Safety and Health Standards Safety and Health Regulations	Protection of workers from Syltherm leaks, fires. Insulation sufficient to prevent burns.
Association Codes and Standards (NFPA, ANSI, ASME, NEMA) National Electric Code Life Safety Code Boiler and Pressure Vessel Code	Fire protection in control buildings. Containment of Syltherm leaks from storage in berms. Toluene system design. Piping thickness, materials.

valves. Scheduled pump maintenance includes an annual inspection; seals, wear rings, and impellers will be replaced as necessary. Corrective maintenance problems will primarily involve concentrator tracking mechanisms. An inventory of spare parts (electronics, cables, plastic panels) for concentrators will be maintained.

Safety considerations for the Case 3 system center largely around the fire hazards associated with Syltherm and toluene systems. Syltherm, with a flash point of 154 C (310 F), presents a potential fire hazard in the case of a system leak. The system design includes deluge fire protection systems in the turbine buildings and around storage tanks. No attempt is made to provide an automatic fire protection system for the collector field. Large Syltherm leaks in the collector field would be detected by the Master Control System, with the leaking section of the field automatically isolated. This would restrict the region of damage due to fire. Toluene leaks, if they should occur, would be restricted to the turbine building; therefore that building should be well ventilated and gas detectors should be utilized. Smoking would be prohibited and all components within the turbine building would be specified for flammable/explosive environment usage.

10.3.2 System Construction Considerations

Preliminary scheduling of the design, procurement, site preparation, and construction of the Case 3 System has been prepared. The total time period, from preliminary specifications through initial start-up, is estimated to be about 24 months. Figure 10.3-4 gives the construction schedule, detailing the various activity areas.

Assumptions used in preparing the schedule are as follows.

- A peak work force of 150 men is anticipated. This includes welders, dish erection crews, laborers, etc.
- An 8-hour day/20-day work month is assumed.
- Seven four-man crews can assemble 28 dishes per week.[11]

10.3.3 System Cost Estimates

Capital cost estimates for the Case 3 System have placed the system cost in 1980 dollars. A breakdown of the various subsystem costs are

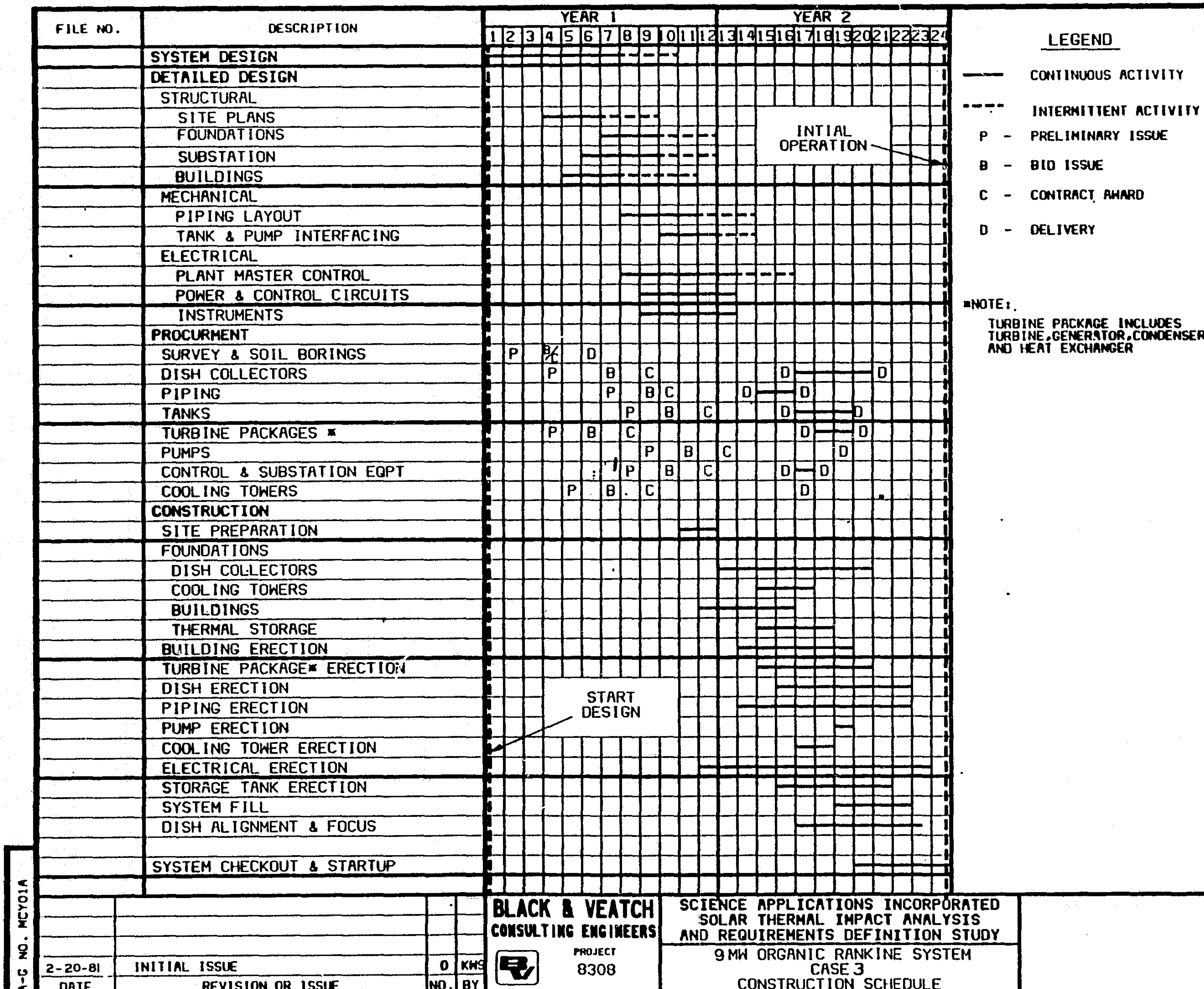

FIGURE 10.3-4 CASE 3 SYSTEM CONSTRUCTION SCHEDULE

listed in Table 10.3-5; contingencies and indirects (engineering, construction management, administration, start-up, and AFDC) have been included, as have been operation and maintenance cost estimates.

The bases for the various subsystem costs are as follows.

- A concentrator cost of $100/m^2 was used (FOB Tyler, Texas). This was in keeping with both the Task I data base,[5] and with DOE cost projections for large production levels.[13]
- Receiver costs of $60/kWe were used, assuming a solar multiple of 1.0, and a turbine generator efficiency of 0.3 for the costing exercise. Again, this was found to be in agreement with DOE projections[12] and the Task I data base.[5]
- Turbine costs differing from the Task I data base were used since the turbine size (50 times larger than the 22 kW unit cited there) and the production rate (1/50 of the Task I value) are different. A cost estimate of $350/kWe for the uninstalled turbine was based on a learning curve reduction of a manufacturer's estimate of $540/kWe for 60 machines per year.[14]
- Storage costs were estimated as per a SERI adaptation of the Shenendoah Solar Total Energy Project trickle oil concept.[4]
- Other system costs were developed by the B&V cost estimating group from vendor information, B&V experience, and other published projects, based on first level material take-offs developed for the system design.
- Operation and maintenance costs are based on estimates from prior B&V solar projects, as well as published O&M projections for other projects.

10.3.4 System Sensitivity Analysis

The Case 3 sensitivity study examines the impact of replacing the nine 1 MWe turbines with a single 9 MWe turbine and adding the required thermal transport piping in lieu of electrical cable. The layout of the nine individual, 84-collector modules is not altered. Within each module, piping and electrical connections remain the same as in the baseline Case 3 system. Figure 10.3-5 shows the overall system layout.

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TABLE 10.3-5. CASE 3 COST SUMMARY

Item		Capital Cost* $
Land		325
Site Preparation		195
Collector Field		13,101
Concentrators	$8,543	
Receivers	907	
Concentrator/Receiver Installation**	2,419	
Foundations (Installed)	1,232	
Thermal Energy Transport		8,694
Piping and Insulation	1,217	
Valves and Fittings	2,003	
Instrument Air System	115	
Installation-support foundations, labor, equipment	5,359	
Thermal Energy Storage		8,062
Media***	941	
Media Containment Equipment	1,381	
Media Circulation Equipment	1,814	
Installation	3,926	
Electric Power Generation		5,242
Turbine, Heat Exchanger, Condenser	3,150	
Cooling Tower, Pumps, Piping	445	
Installation	1,647	
Electrical Distribution		2,990
Material	1,647	
Installation	1,343	
Master Control		1,500
Balance of Plant		886
Subtotal		40,995
Contingencies (15 per cent)		6,149
Total Direct Costs		47,144
Indirects (32 per cent)		15,086
Total		62,230

Operations and Maintenance Cost: $900,000/year

*1,000's of 1980 dollars.
**Includes shipping costs per G. E. shipment packaging criteria.(12)
***Includes Syitherm in piping.

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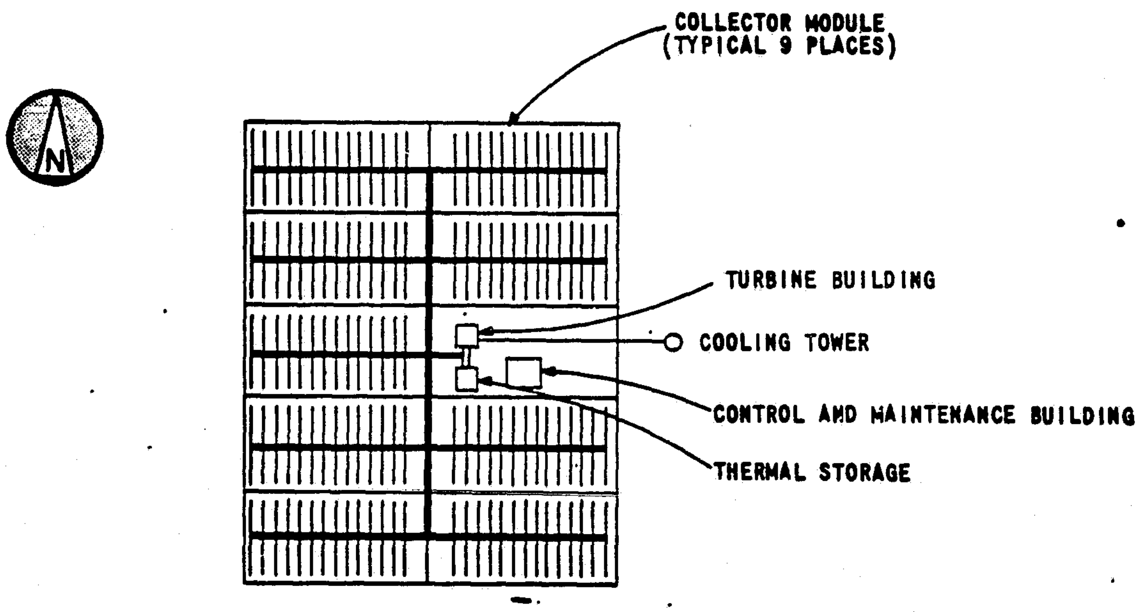

PLANT LAYOUT FOR SYSTEM WITH 9 MWe ORC TURBINE

FIGURE 10.3-5

The change to a single turbine impacts system performance and system cost. System performance is upgraded a small amount (approximately one percentage point) due to increased turbine efficiency; the exact gain in efficiency is unknown.[15]

System cost changes because of several factors included in the following.

- Costs for a single 9 MWe turbine are somewhat less than for nine 1 MWe turbines. An exact value for savings is not known;[15] therefore the cost per kW has been assumed to be reduced by 10 per cent. This reduction assumes that a significant market exists for 9 MWe turbines. The validity of this assumption cannot be established by presently available data. A significant market for 1 MWe turbines (waste heat recovery systems) has been identified apart from the solar industry; however, a similar market for 9 MWe systems has not been identified.
- Costs for a single storage system are less than for nine separate storage systems.
- Piping system costs increase due to additional piping connecting the modules.
- Costs for a single turbine building are less than for nine separate buildings.
- Electrical costs decrease as a single large substation replaces nine smaller secondary substations.

System costs for the baseline modular system and the single turbine system are summarized in Table 10.3-6.

The increased cost effectiveness obtained by utilizing a single turbine is not unexpected. (This was taken into consideration in the selection of the module approach in Case I, as per Table 10.1-1.) However, the potential cost effectiveness of the large system must be weighed against the flexibility of the 1 MWe module approach in providing a variety of power levels in the 1 to 10 MWe range.

TABLE 10.3-6. SYSTEM COST SENSITIVITY TO TURBINE SIZE CHANGE

Item	Modular System $	9 MWe Turbine System $	Change $
Land	325	325	0
Site Preparation	195	195	0
Collector Field	13,101	13,101	0
Thermal Energy Transport	8,694	9,374	680
Thermal Energy Storage	8,062	6,507	-1,555
Electric Power Generation	5,242	4,718	-524
Electrical Distribution	2,990	2,450	-540
Master Control	1,500	1,500	0
Balance-of-Plant	886	491	-395
	40,995	38,661	-2,334
Contingencies and Indirects	21,235	20,026	-1,209
	62,230	58,687	-3,543

NOTE: All costs in thousands of 1980 dollars.

10.3.5 Case 3 References

1. Private communication to W. M. Bohon, Black & Veatch, from Martin Sorkin and Robert Stillwell, Dow Corning Corporation, September 10, 1980.

2. General Electric, Solar Total Energy-Large Scale Experiment at Shenendoah, Georgia, Final Report, DOE Contract No. EG77-C-04-3985, September 1978.

3. Private communication to L. E. Stoddard, Black & Veatch, from Robert Copeland, SERI, February 11, 1981.

4. R. J. Copeland, M. E. Karpuk, and J. Ullman, A Preliminary Screening of Thermal Storage Concepts for Water/Steam and Organic Fluid Solar Thermal Receiver Systems, SERI/TR-631-647, April 1980.

5. Science Applications, Incorporated, Solar Thermal Plant Impact Analysis and Requirements Definition Study, Summary Report for Tasks 1, 2, and 3, JPL Contract No. 955238, September 7, 1979.

6. "Local Climatological Data, 1978, Phoenix, Arizona," National Climatic Center, Ashville, North Carolina.

7. Jet Propulsion Laboratory, Proceedings of the First Semi-Annual Distributed Receiver Systems Program Review, DOE/JPL-1060-33, April 15, 1980.

8. Private communication to E. L. Doty, Black & Veatch, from M. D. Santucci, Sunstrand, March 28, 1979.

9. Private communication to W. M. Bohon, Black & Veatch, from Doug Lacey, Manager of Marketing, Sunstrand, August 28, 1980.

10. Private communication to W. M. Bohon, Black & Veatch, from Doug Lacey, Manager of Marketing, Sunstrand, September 8, 1980.

11. Private communication to L. E. Stoddard, Black & Veatch, from Jeff Zimmerman, General Electric, September 8, 1980.

12. Private communication to S. L. Levy, Black & Veatch, from Jeff Zimmerman, General Electric, September 11, 1980.

13. Private communication to L. E. Stoddard, Black & Veatch, from John Lucas, Jet Propulsion Laboratory, August 4, 1980.

14. Private communication to W. M. Bohon, Black & Veatch, from Doug Lacey, Manager of Marketing, Sunstrand, August 22, 1980.

15. Personal communication to L. E. Stoddard, Black & Veatch, from Doug Lacey, Manager of Marketing, Sunstrand, February 19, 1981.

16. Stearns-Roger Services, Inc., Cost and Performance of Thermal Storage Concepts in Solar Thermal Systems, Final Design Review, January 21, 1981.

17. Private communication to L. E. Stoddard, Black & Veatch, from Victor Burolla, Sandia Laboratories, Livermore, June 24, 1981.

10.4 CASE 4: LARGE INVESTOR-OWNED UTILITY--9 MWe

Case 4 is defined to be a 9 MWe parabolic dish system which is part of a large investor-owned utility located near Phoenix, Arizona. Distinguishing features of the case definition are as follows:

- General Electric Low Cost Concentrator,
- Central generation via a single nine MWe steam turbine,
- Five hours of thermal storage,
- Thermal energy transport via steam, and
- A sensitivity study which evaluates the impact of changing the turbine inlet steam temperature.

The design of the system is based on a 1990 time frame. This lead time allows extrapolation of current technological developments as well as reduction of key component costs to a "mature" level.

The system is configured for a noon, March 21 design point, with an assumed insolation level of 950 watts/m^2 (301 Btu/h/ft^2). By designing the system for a typical clear day, noon peak insolation, the system capability to handle peak solar power inputs is assured. As in the designs for Case 1 and Case 3, the collector system is sized so as to just fill the five-hour thermal storage on a clear March 21. The system solar multiple (design point power from the collector field divided by power to the turbine) is 1.6.

10.4.1 System Description

The Case 4 system has been designed within the framework of the previously given case definition. Key design characteristics include the following; rationale for these design decisions are discussed in Table 10.4-1.

- Steam at 510 C (950 F) has been selected over pressurized water as the collector field heat transfer medium.
- A "split" collector field is utilized (similar to the GE Small Power System Experiment, Phase I, system concept)[1,2] with separate boiler and superheater collectors. Wet saturated steam from the boiler field section is collected in a steam accumulator (essentially a boiler drum); dry saturated steam is transported to the superheater field section, while saturated water is recirculated to the boiler section.

TABLE 10.4-1. KEY DESIGN DECISIONS FOR CASE 4

Key Design Decision	Favoring Rationale	Opposing Rationale
Split field (separate boiler and superheater collectors) rather than once-through system.	Individual collector controls not required as in once-through system. Potentially lower piping costs since boiler return lines can be carbon steel. Potentially higher overall collector efficiency since most collectors are relatively low temperature. High temperature (superheater) collectors can be located closest to the turbine, reducing piping thermal losses and costs for alloy steel piping.	Two type of receivers required. Slightly higher auxiliary pumping power requirements.
Steam (rather than water) as collector heat transfer medium	System pressure requirements significantly less stringent than for pressurized water. Steam system can operate at (1,480 psia)/(950 F); pressure for water system at (700 F) must be in excess of (3,100 psia). Steam, by virtue of the phase change, has higher enthalpy than pressurized water. Higher temperatures and thereby higher cycle efficiencies available with steam.	Water system allows series storage such that system output when operating from solar or storage is constant; steam system requires parallel storage with a 30 per cent cycle efficiency penalty when operating from storage. Steam has higher specific volume leading to larger pressure drops for a given pipe size.
Oil/rock thermocline storage rather than molten salt	Significantly less expensive than a two stage salt system. Oil/rock storage is appropriate for buffer storage or for rapid transition from solar operation to storage operation. (Steam from rock/oil storage is the appropriate pressure/temperature for injection into the second admission part of a dual admission steam turbine, allowing combined solar/storage operation. Steam from salt storage system at ~482 C (900 F) is not compatible for combined solar/storage operation, or for rapid transition from solar to storage or vice versa.)	Salt system can produce higher temperature steam (~950 F) than can an oil system, giving a higher cycle efficiency when operating from storage.

- Thermal storage uses a parallel oil/rock thermocline system.[3,4]
- Turbine inlet steam conditions from the solar field are 10.1 MPa (1,465 psi)/510 C (950 F). Steam from storage at 2.65 MPa (385 psi)/274 C (525 F) is input to the second admission level of a dual admission turbine.

10.4.1.1 System Design Requirements. This subsection presents specific design requirements for the Case 4 system. Topics addressed include the following.

- Site conditions,
- Site arrangement,
- System design point requirements,
- System functional requirements, and
- Standards and regulations.

Site Conditions. The site for the Case 4 system is in the vicinity of Phoenix, Arizona. As with Case 3, it is assumed that the site selection can be made to minimize site preparation, erecting of electrical transmission lines, and other plant support items such as access roads. The previously given Table 10.3-2 lists the assumed site conditions.

Site Arrangement. The physical arrangement for the Case 4 system is shown on Figure 10.4-1. The systems consists of 448 boiler collectors located in 6 boiler field modules, and 180 superheater collectors located in 4 superheater field modules. The superheater modules are positioned adjacent to the central turbine to minimize the amount of high temperature, 510 C (950 F), steam pipe, thereby minimizing costs and thermal losses. Two steam accumulators are located adjacent to the superheater fields; the use of two accumulators, rather than a single accumulator near the turbine, also reduces the amount of pipe required.

System Design Point Requirements. The system is designed to provide rated power (9 MWe net) at noon March 21. Figure 10.4-2 shows the functional configuration of the system as well as identifying design point temperatures, pressures, flow rates, and power traces. Design details for the individual subsystems are listed on Table 10.4-2.

System Functional Requirements. The previous section on system design point characteristics has described the Case 4 system configuration as well

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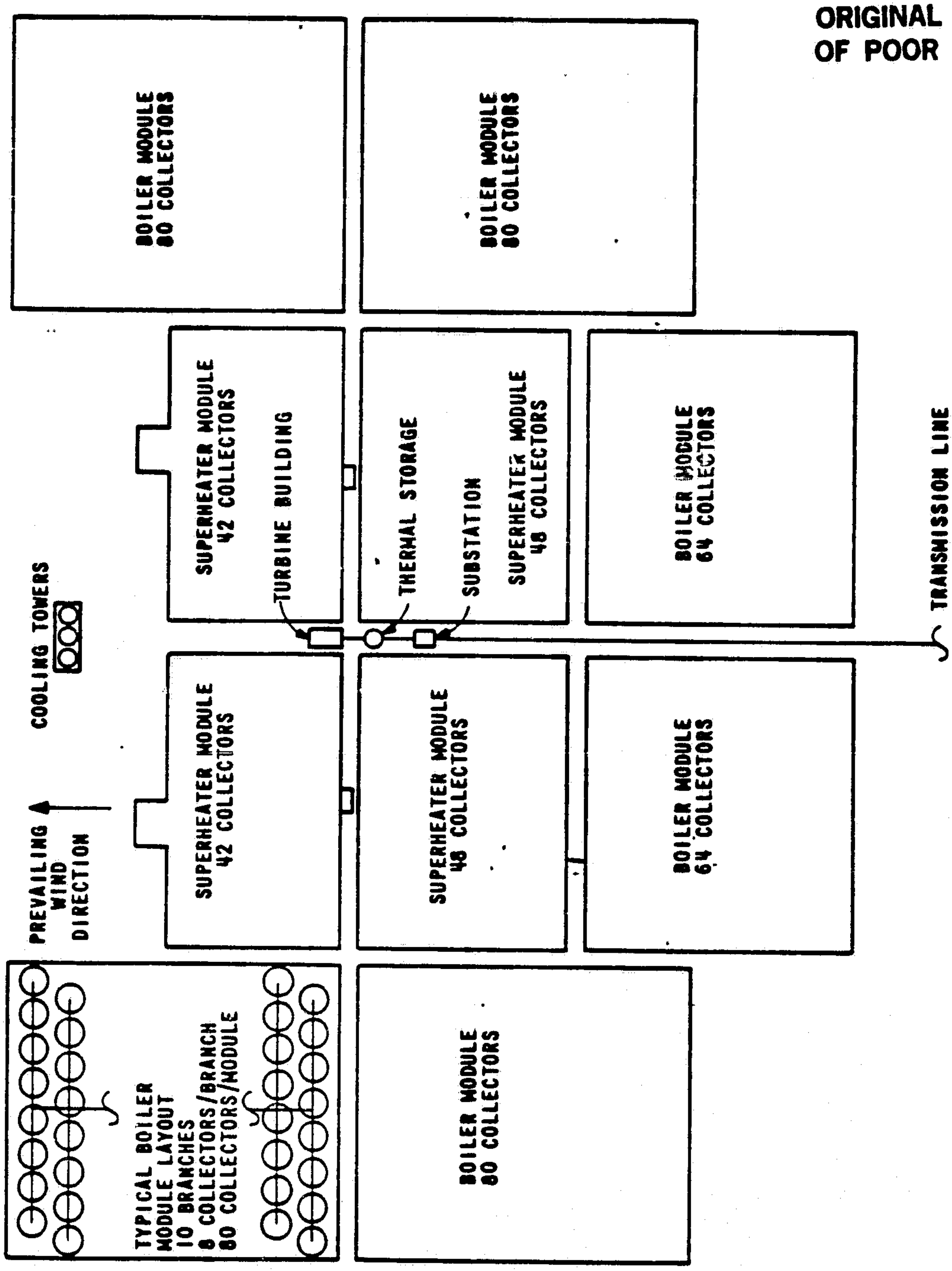
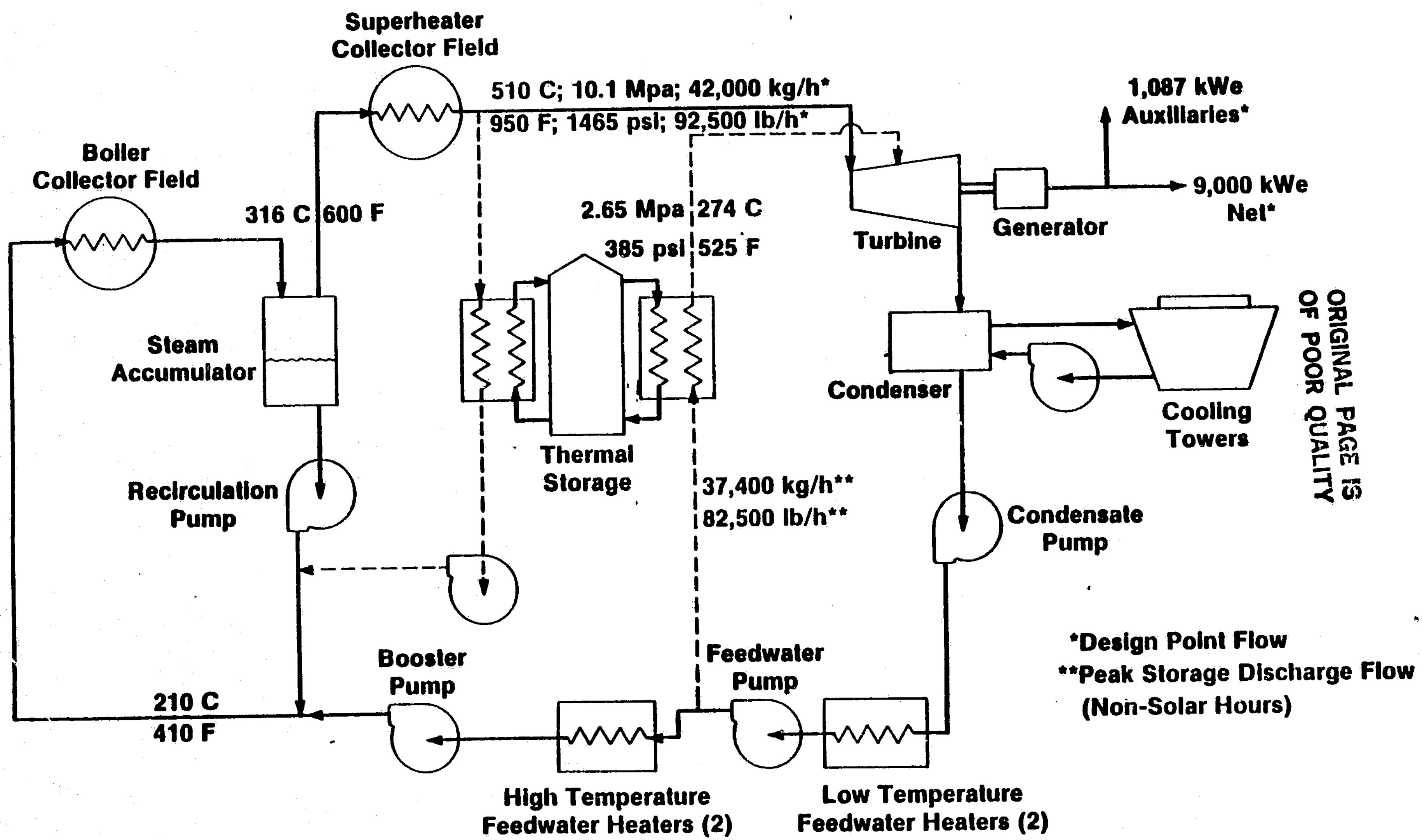


FIGURE 10.4-1. CASE 4 SYSTEM PLAN ARRANGEMENT



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Note: Feedwater Extraction Lines
Omitted for Clarity

FIGURE 10.4-2 CASE 4 FUNCTIONAL FLOW DIAGRAM

TABLE 10.4-2. CASE 4 SUBSYSTEM DESIGN SUMMARIES

COLLECTOR SUBSYSTEM

Parameter	D. P. Value*
Concentrator[5]	
Dish Diameter, m (ft)	12 (39)
Effective Aperture Area, m^2 (ft^2)	111 (1,190)
Reflectivity	0.84
Shading Factor	0.94
Intercept Factor	0.96
Concentrator Effectiveness	0.74
Boiler Receiver**	
Aperture Diameter, m (ft)	0.25 (0.82)
Inlet Temperature, C (F)	210 (410)
Outlet Temperature, C (F)	316 (600)
Power Input, kWt (MBtu/h)	79.9 (0.273)
Power Output, kWt (MBtu/h)	77.8 (0.266)
Efficiency	0.97
Mass Flow Rate, kg/sec (lbm/sec)	0.047 (0.10)
Superheater Receiver**	
Aperture Diameter, m (ft)	0.25 (0.82)
Inlet Temperature	316 (600)
Outlet Temperature	510 (950)
Power Input, kWt (MBtu/h)	79.9 (0.273)
Power Output, kWt (MBtu/h)	76.0 (0.259)
Efficiency	0.95
Mass Flow Rate, kg/sec (lbm/sec)	0.11 (0.23)

*Design point value.

**Receiver design characteristics have been synthesized for this application.

ELECTRIC POWER GENERATION SUBSYSTEM[3]

Parameter	D. P. Value
Cycle	Subcritical Rankine
Working Fluid	Water/Steam
Turbine Type	Dual Automatic Admission (Throttle and Second Level) Tandem Compound, Single Flow Condensing
Number of Feedwater Heaters	4
Cycle Heat Rejection	Wet, Mechanical Draft Cooling Towers
Operation From Collector Field	
Gross electric output, kWe	10,087
Electric auxiliary load, kWe	1,087
Net electric output, kWe	9,000
Turbine throttle pressure, MPa (psig)	10.1 (1,465)
Turbine throttle temperature, C (F)	510 (950)
Gross cycle efficiency	0.347
Thermal input, kWt (MBtu/h)	29,070 (99.21)
Turbine throttle flow rate, kg/h (lb/h)	42,000 (92,500)
Operation From Thermal Storage	
Gross electric output, kWe	6,147
Electric auxiliary load, kWe	617
Net electric output, kWe	5,530
Turbine throttle pressure, MPa (psig)	2.65 (385)
Turbine throttle temperature, C (F)	274 (525)
Gross cycle efficiency	0.244
Thermal input, kWt (MBtu/h)	25,240 (86.13)
Turbine throttle flow rate, kg/h (lb/h)	37,400 (82,500)

THERMAL ENERGY TRANSPORT SUBSYSTEM

- General piping layout per Figure 10.4-1.
- Detailed piping layout similar to GE First Small Power System Experiment piping layout.[1]
  - -- Pneumatic control valve for each 8-collector branch.
  - -- Automatic isolation of 8-collector branches.
  - -- Manual isolation of each collector, half-branch, and branch.
- Superheated steam piping, valves, and fittings of A335 Grade P2, 1-1/2 Cr, 1/2 Mo alloy steel.
- Feedwater, saturated water/steam, and saturated steam piping, valves, and fittings of A106 Grade B carbon steel.
- Insulated to reduce thermal losses to 5 per cent of rated power.
- All joints welded.
- Expansion loops provided to allow for thermal growth.
- Per standard power plant practices, the minimum pipe size used is 19.1 mm (3/4 inch) so that accidental breakage is avoided.
- Condensate removed from pipelines via steam traps and condensate return lines.
- Availability of high temperature, high pressure flexible hoses is assumed.

THERMAL ENERGY STORAGE SUBSYSTEM[2,4]

Parameter	Value
Configuration	One-Tank, Parallel Storage
Medium	Oil/Rock
Storage Principle	Thermocline, sensible heat storage
Capacity, MWht (MBtu); h	126.2 (430); 5
Maximum Discharge Rate, MWt (MBtu/h)	25.2 (86.1)
Oil Temperature; Charged, C (F)	302 (575)
Oil Temperature; Discharged, C (F)	218 (425)
Discharge Temperature; Steam Side, C (F)	274 (525)
Discharge Pressure; Steam Side, MPa (psig)	2.65 (385)

MASTER CONTROL SUBSYSTEM

- Central Control Mini-computer.
- Main Control Panel.
- Programmers Console.
- CRT Displays.
- Printer.
- Interface Hardware.
  - -- Turbine Controller.
  - -- Collector Controllers.
  - -- Energy Transport Controllers.
  - -- System Instrumentation.

BALANCE OF PLANT

- Buildings.
  - -- Turbine.
  - -- Central Control and Maintenance.
  - -- Warehouse (spare parts inventory).
- Maintenance Equipment.
  - -- Truck.
  - -- Crane.
  - -- Washing Vehicle.
  - -- Tools.
- Fire Protection System.
- Plant Lighting System.
- Roads.
- Security Fence.

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as design point temperatures, flow rates, and powers. This section identifies various system operating modes and the functional roles of the various subsystems in achieving those modes.

The overall system has been designed for a rated net power of 9.0 MWe. System operating modes are similar to those discussed for Case I in Subsection 10.1.1.1 under System Functional Requirements; a key difference is that the Case 4 system, when operating from storage, generates at a level significantly below rated power (i.e., 5.5 MWe net when operating from storage) due to lower steam temperature/pressure and therefore lower cycle efficiency.

Operation of the Case 4 system is illustrated in Figure 10.4-3. The system is sized such that on a clear March 21 day storage is just filled. As shown on Figure 10.4-3a, power can be generated from storage for five hours; however, the power output when generating from storage is reduced. Figure 10.4-3b shows operation on a cloudy day. The storage acts as a buffer, allowing generation at a reduced level when the rated solar turbine input power is not available due to cloud passage. Operation from solar and storage combined is possible, with a cycle efficiency between that of solar input only and storage input only.

Individual subsystems have been designed to meet the overall system functional requirements. The remainder of this section will address subsystem functional requirements.

In achieving the above system operating modes the <u>Collector Subsystem</u> must fulfill the following functional requirements.

- Two-axis tracking of the sun,
- Heat 210 C (410 F) feedwater to generate wet steam (90 per cent steam) at 316 C (600 F),
- Delivery up to 77.8 kWt (266,000 Btu/h) per boiler collector,
- Superheat dry 316 C (600 F) steam to 510 C (950 F),
- Deliver up to 76 kWt (259,000 Btu/h) per superheater collector,
- Operate in winds up to 50 km/h (31 mph),
- Slew to stow in winds up to 80 km/h (50 mph),

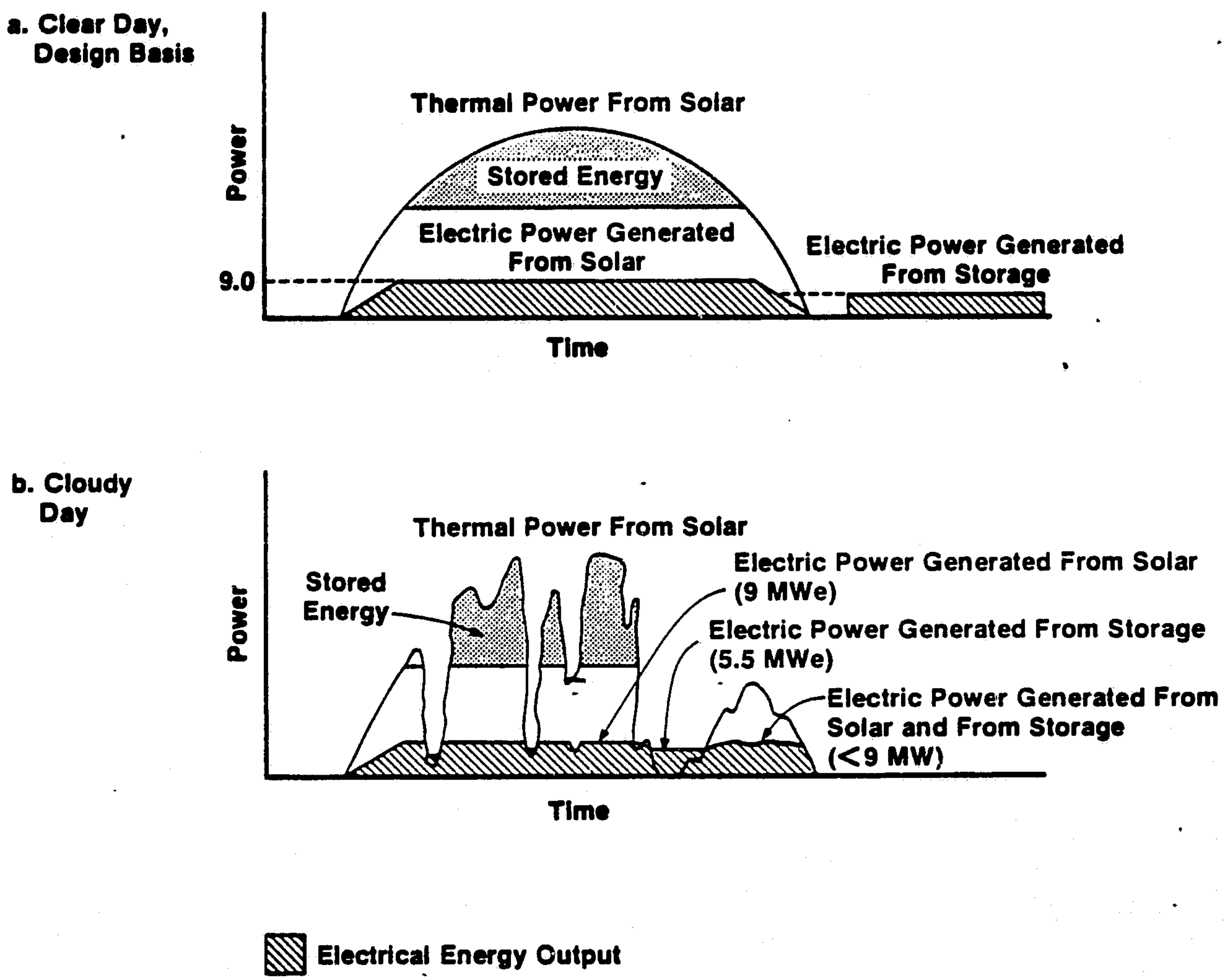

FIGURE 10.4-3 CASE 4 OPERATING MODES

- Survive in stowed position for winds up to 145 km/h (90 mph), and
- Survive 1/4-g lateral seismic load.

The Thermal Energy Transport System must fulfill the following functional requirements.

- Transport feedwater and steam to and from the collector field with thermal losses not to exceed 2.4 MWt (7.8 MBtu/h) (5 per cent at the design point),
- Provide automatic isolation of piping to collector branches and manual isolation of collectors, and
- Trap and remove condensate from steam lines.

The Thermal Storage Subsystem must fulfill the following requirements.

- Provide storage capacity to allow thermal input to the turbine for 5 hours operation,
- Accept charge rates ranging from 2.4 MWt to 48 MWt of 2.65 MPa (385 psi)/274 C (525 F) steam,
- Provide discharge rates ranging from 1.3 MWt to 25.2 MWt,
- Maintain storage medium quality and subsystem integrity, and
- Provide for thermal losses to be less than one per cent of design point capacity per hour.

The Electric Power Generation Subsystem has the following functional requirements.

- Generate up to a gross power of 10.1 MWe (9.0 MWe net) from solar,
- Generate up to a gross power of 6.1 MWe (5.5 MWe net) from storage, and
- Allow rapid change from generating via solar to generating via storage, vice versa, or via both storage and solar.

The Central Control System must fulfill the following functional requirements.

- Allow dispatcher control of turbine output power.
- Send command signals to individual collectors to track, "defocus", or stow.

- Monitor energy in thermal storage.
  - "Defocus" an appropriate number of collectors when storage is filled to capacity and the turbine is operating at rated power.
  - Command all collectors to track the sun when the system can utilize the full output of the collector system.
- Monitor system temperatures, pressures, and flows.
- Provide warnings and alarms for faulty operation.
  - High temperatures and pressures.
  - Indications of pipe ruptures.
- Provide built-in automatic system start-up and shut-down algorithms for the collector field.

Standards and Regulations. The Case 4 system design is responsive to a number of laws, ordinances, codes, and standards. Table 10.4-3 lists applicable regulations, along with the more significant impacts of those regulations.

10.4.1.2 Operational Requirements. The day-to-day operational factors of the Case 4 system consists of four elements.

- Personnel
- Consumables
- Maintenance
- Safety

Operations and maintenance personnel required to staff the plant include six full time workers. Three of these workers are plant operators; duty hours are structured so as to cover average system operation 17 hours per day, 7 days per week. During cloudy days, operators perform routine inspections and maintenance tasks. The remaining workers are assigned full time to maintenance tasks, the chief task being washing of the collectors. No allocation of administrative personnel has been made.

The primary consumable for the system is collector washing fluid. A wash and rinse method is proposed, with a total water usage of 58,000 liters (16,000 gallons) per month [the basis is 95 liters (25 gallons) per wash per concentrator, and monthly washing]. The primary maintenance

TABLE 10.4-3. APPLICABLE STANDARDS AND REGULATIONS

Requirement	Major Impact
Federal Laws and Ordinances Clean Air Act Noise Control Act National Environmental Policy Act Federal Water Pollution Control Act Toxic Substance Control Act	Handling of effluents (e.g., steam accumulator and heat rejection blowdowns).
OSHA Codes and Standards Occupational Safety and Health Standards Safety and Health Regulations	Establishment of safety procedures. Insulation sufficient to prevent burns.
Association Codes and Standards (NFPA, ANSI, ASME, NEMA) National Electric Code Life Safety Code Boiler and Pressure Vessel Code	Electrical system specification and installation. Steam accumulator wall thickness and materials. Piping thickness and materials.

activity will be the washing of concentrators. A washing vehicle which washes and then rinses the concentrator will be used. It is estimated that the cleaning process, which will be conducted once each month, will take 15 minutes per concentrator; this amounts to about 20 man-days per month. Other routine maintenance tasks will include inspection of system components for malfunctions (e.g., piping network for evidence of leaks; collectors for tracking problems). Scheduled maintenance for valves includes annual inspection, packing, and calibration of control valves. Scheduled pump maintenance includes an annual inspection; seals, wear rings, and impellers will be replaced as necessary. Corrective maintenance problems will primarily involve concentrator tracking mechanisms. An inventory of spare parts (electronics, cables, plastic panels) for concentrators will be maintained.

The key safety concern for the Case 4 system is the possibility of burns. Burns or eye injury from concentrators should not be a problem since the danger is primarily at the concentrators focal points; safety procedures would be developed to assure that personnel will not be on the danger zone with concentrators tracking. The possibility of burns as a result of steam line ruptures is minimized by adhering to the ASME Boiler and Pressure Vessel Codes; burns from contact with hot pipes are eliminated by appropriate insulation of pipes and other hot surfaces.

10.4.2 System Construction Considerations

Preliminary scheduling of the design, procurement, site preparation, and construction of the Case 4 system has been prepared. The total time period, from preliminary specifications through initial start-up, is estimated to be about 24 months. Figure 10.4-4 gives the construction schedule, detailing the various activity areas.

Assumptions used in preparing the schedule are as follows.

- A peak work force of 150 men is anticipated. This includes welders, dish erection crews, laborers, etc,
- An 8-hour day/20-day work month is assumed, and
- Seven four-man crews can assemble 28 dishes per week.

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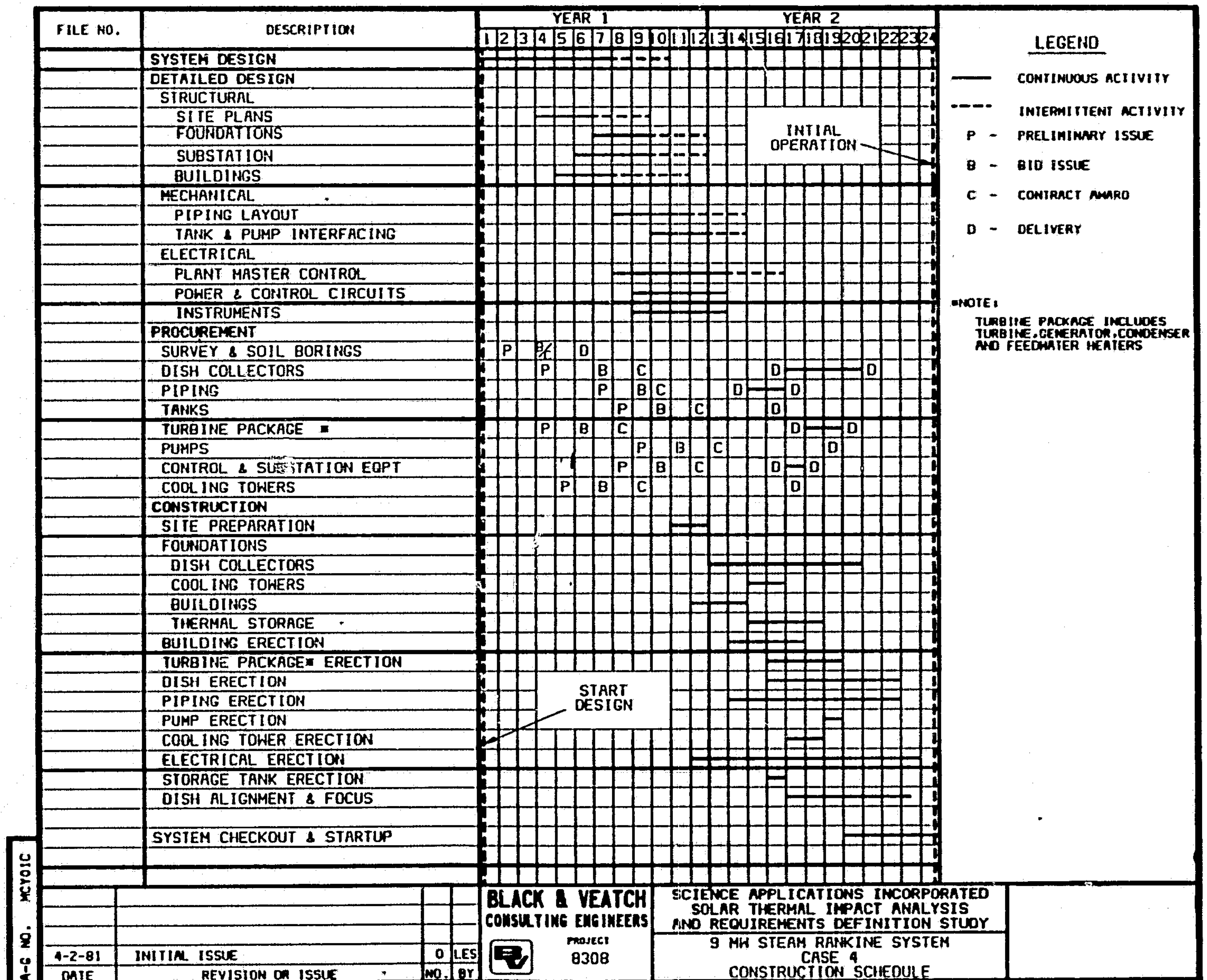

FIGURE 10.4-4 CASE 4 SYSTEM CONSTRUCTION SCHEDULE

10.4.3 System Cost Estimates

Capital cost estimates for the Case 4 system have placed the system cost in 1980 dollars. A breakdown of the various subsystem costs, along with assumed contingencies and indirect costs are listed in Table 10.4-4; estimated operation and maintenance cost are also included.

The bases for the various subsystem costs are as follows.

- A concentrator cost of $\$100/m^2$ was used (FOB Tyler, Texas). This was in keeping with both the Task I data base,[6] and with DOE cost projections for large production levels.[7]
- Receiver costs of \$60/kWe were used, assuming a solar multiple of 1.0, and a turbine generator efficiency of 0.3 for the costing exercise.[6,7]
- Electric power generation and thermal storage costs were based on adaptations of costs for similar systems/components in the McDonnell Douglas Central Receiver 10 MWe Pilot Plant.[3]
- Other system costs were developed by the B&V cost estimating group from vendor information, B&V experience, and other published projects, based on first level material take-offs developed for the system design.
- Indirect costs include engineering and construction management fees, administration and start-up costs, and AFDC.
- Operation and maintenance costs are based on estimates from prior B&V solar projects, as well as published O&M projections for other projects.

10.4.4 Sensitivity Study

The Case 4 sensitivity study analyses the impact on system performance of changing operating temperatures. Two such changes have been evaluated: an increase of turbine inlet temperature (TIT) of 28 C (50 F) to 538 C (1,000 F), and a decrease of TIT by 28 C (50 F) to 482 C (900 F). In accordance with the case definition, the system design is not changed for this analysis. It is assumed that the turbine input power is not changed. Results of the study are recorded in Table 10.4-5.

TABLE 10.4-4. CASE 4 COST SUMMARY

Item		Capital Cost* $
Land		287
Site Preparation		173
Collector Field		11,135
Concentrators	$7,096	
Receivers	1,005	
Concentrator/Receiver Installation	1,620	
Foundations (Installed)	1,414	
Thermal Energy Transport		9,918
Piping and Insulation	1,755	
Valves and Fittings	971	
Instrument Air System	29	
Installation-support foundations, labor, equipment	7,163	
Thermal Energy Storage		6,099
Media	412	
Equipment	4,863	
Installation	824	
Electric Power Generation		5,846
Turbine Generator, Condenser, etc.	3,905	
Heat Rejection	984	
Steam Accumulators	290	
Installation	667	
Electrical Distribution		1,955
Material	993	
Installation	962	
Master Control		1,500
Balance of Plant		494
Subtotal		37,407
Contingencies (15 per cent)		5,611
Total Direct Costs		43,018
Indirects (32 per cent)		13,766
Total		56,784

Operations and Maintenance Cost: $850,000/year

*1,000's of 1980 dollars.

**Includes shipping costs per G. E. shipment packaging criteria.(12)

TABLE 10.4-5. SYSTEM PERFORMANCE SENSITIVITY TO STEAM TEMPERATURE

	Turbine Inlet Temperature		
Item	482 C (900 F)	510 C (950 F)*	538 C (1,000 F)
Design Point			
Thermal Power from Field, MWt	46.5	46.1	45.7
Thermal Power to Storage, MWt	17.4	17.0	16.6
Thermal Power to Turbine,** MWt	29.1	29.1	29.1
Net Power Generated, MWe	8.75	9.00	9.23
March 21 Daily Total			
Thermal Energy from Field, MWht	415	411	407
Thermal Energy to Storage, MWht	132	129	126
Thermal Energy to Turbine, MWht	411	408	405
Net Energy Generated, MWhe	121	124	126

*Case 4 Baseline System.

**Thermal power to turbine was assumed to be the same for each of the three systems.

For the 28 C (50 F) increase in temperature, the turbine cycle efficiency when operating from solar increases by about 2.3 per cent, yielding an increase in design point net power generation to 9,230 kWe. The increase in operating temperature decreases the efficiency of the superheater collectors slightly (about three per cent), resulting in a drop of one per cent in the overall design point field efficiency. The cycle efficiency of the turbine when operating from storage is not altered; the storage temperature cannot be raised, due to media temperature limits.

For the 28 C (50 F) decrease in temperature, the turbine cycle efficiency when operating from solar decreases by about 2.5 per cent, with a resultant net output of 8,750 kWe. The decrease in temperature increases the superheater collector efficiency by about three per cent; the overall design point field efficiency rises by about one per cent. The turbine cycle efficiency when operating from storage does not change; the baseline system storage outlet temperature of 274 C (525 F) can also be achieved with 482 C (900 F) steam from solar.

10.4.5 References

(1) General Electric Company, The First Small Power System Experiment, Phase I, Final Technical Report, NASA-CR-162417, May 1979.

(2) Private communication to S. M. Clark, Black & Veatch, from H. E. Jones, Program Manager, General Electric, March 4, 1981.

(3) McDonnell Douglas, Central Receiver Solar Thermal Power System, Phase I, CDRL Item 2, Pilot Plant Preliminary Design Report, SAN/1108-8/6, October 1977.

(4) R. J. Copeland, M. E. Karpuk, and J. Ullman, A Preliminary Screening of Thermal Storage Concepts for Water/Steam and Organic Fluid Solar Thermal Receiver Systems, SERI/TR-631-647, April 1980.

(5) Jet Propulsion Laboratory, Proceedings of the First Semi-Annual Distributed Receiver Systems Program Review, DOE/JPL-1060-33, April 15, 1980.

(6) Science Applications, Incorporated, Solar Thermal Plant Impact Analysis and Requirements Definition Study, Summary Report for Tasks 1, 2, and 3, JPL Contract #955238, September 7, 1979.

(7) Private communication to L. E. Stoddard, Black & Veatch, from John Lucas, Jet Propulsion Laboratory, August 4, 1980.

10.5 CASE 5: SIX MWe SYSTEM WITH PROCESS HEAT

Case 5 is defined to be a 6 MWe cogeneration parabolic dish system located at an industry in the Fort Worth, Texas area. The system is a modification of the Case 4 system to allow production of process steam along with generation of 6 MWe. The case definition calls for the collector field size and the energy transport system to be the same as in Case 4. The electrical generation in Case 5 is decreased from 9 MWe net in Case 4 to the 6 MWe level. The original case definition called for Case 5 to have no thermal storage (Case 4 had five hours of thermal storage). However, it was redefined because the large solar multiple (about 1.6) of Case 4 results in a collector field oversized for a 6 MWe cogeneration facility unless storage is included, and because incorporation of thermal storage in the system makes sense from an operational standpoint. First, it serves as a buffer against solar power transients. This is of key importance in its impact on the process heat availability. Because the system is connected to the Fort Worth municipal utility grid, rapid transients in plant electrical generation can be handled easily; however, with process heat backup taken as a package boiler, rapid transients in process heat are not as easily met. Therefore storage, as a buffer, is useful operationally. Second, storage will increase the operational day for the solar system.

10.5.1 System Description

The Case 5 system is similar to the Case 4 system in several respects. In accordance with the Case 5 definition, the collector field size (as well as field arrangement) is the same as in Case 4. A "split" collector field[1, 2] having 448 boiler collectors and 180 superheater collectors is utilized. Likewise, the thermal transport system is identical to that of Case 4, as is the thermal storage system.

Two key design decisions have been made in developing the cogeneration turbine cycle for Case 5. First, a noncondensing turbine cycle has been selected. Use of a noncondensing turbine eliminates the waste of heat caused by condenser heat rejection, resulting in a more efficient system. The use of the noncondensing turbine requires that there is a demand for process steam any time electrical power is generated and vice

versa. It is assumed that this requirement is acceptable for the Case 5 application. The second design decision is the selection of a process steam temperature of about 149 C (300 F). A study[3] has shown that 42 per cent of all industrial process heat energy used by facilities in the 10 MWt and 30 MWt size range is between 121 C and 232 C (250 F and 450 F). Because the Case 5 process steam product (~22 MWt) falls into that size range, a 149 C (300 F) process steam temperature is appropriate.

Site Conditions. The site for the Case 5 system is the vicinity of Fort Worth, Texas. The previously given Table 10.1-2 lists assumed site conditions. As with Case 1, it is assumed that the site selection can be made to minimize site preparation, and that plant support items such as roads, electrical grid connections, and water supply are readily available.

Site Arrangement. The physical arrangement for the Case 5 system, shown in Figure 10.5-1, is a slight modification of the Case 4 system layout. It is assumed that the facility utilizing the process steam is located on the perimeter of the collector field. No cooling towers are required for the Case 5 system.

System Design Point Requirements. The system is designed to provide rated power (6 MWe net, 22.2 MWt of process steam) at noon March 21. The functional configuration and state points of the system are shown in Figure 10.5-2. Design details for Case 5 (many of which are identical to Case 4) are listed in Table 10.5-1.

System Functional Requirements. The Case 5 system is designed to operate from solar only, from storage only, or from a combination of solar and storage. Cogeneration of electrical power and process steam must be coincident; i.e., electricity cannot be generated without production of process steam and vice versa. When operating from solar only, and when the thermal input power to the turbine is equal to or greater than 29.1 MWt (99.2 MBtu/h), the system has a net electrical output capability of 6 MWe, and a process steam output capability of 22.2 MWt (75.7 MBtu/h). When solar thermal turbine input power is less than 29.1 MWt, generation of electricity and process steam is correspondingly less. When operating from storage only, maximum thermal input to the turbine second admission level

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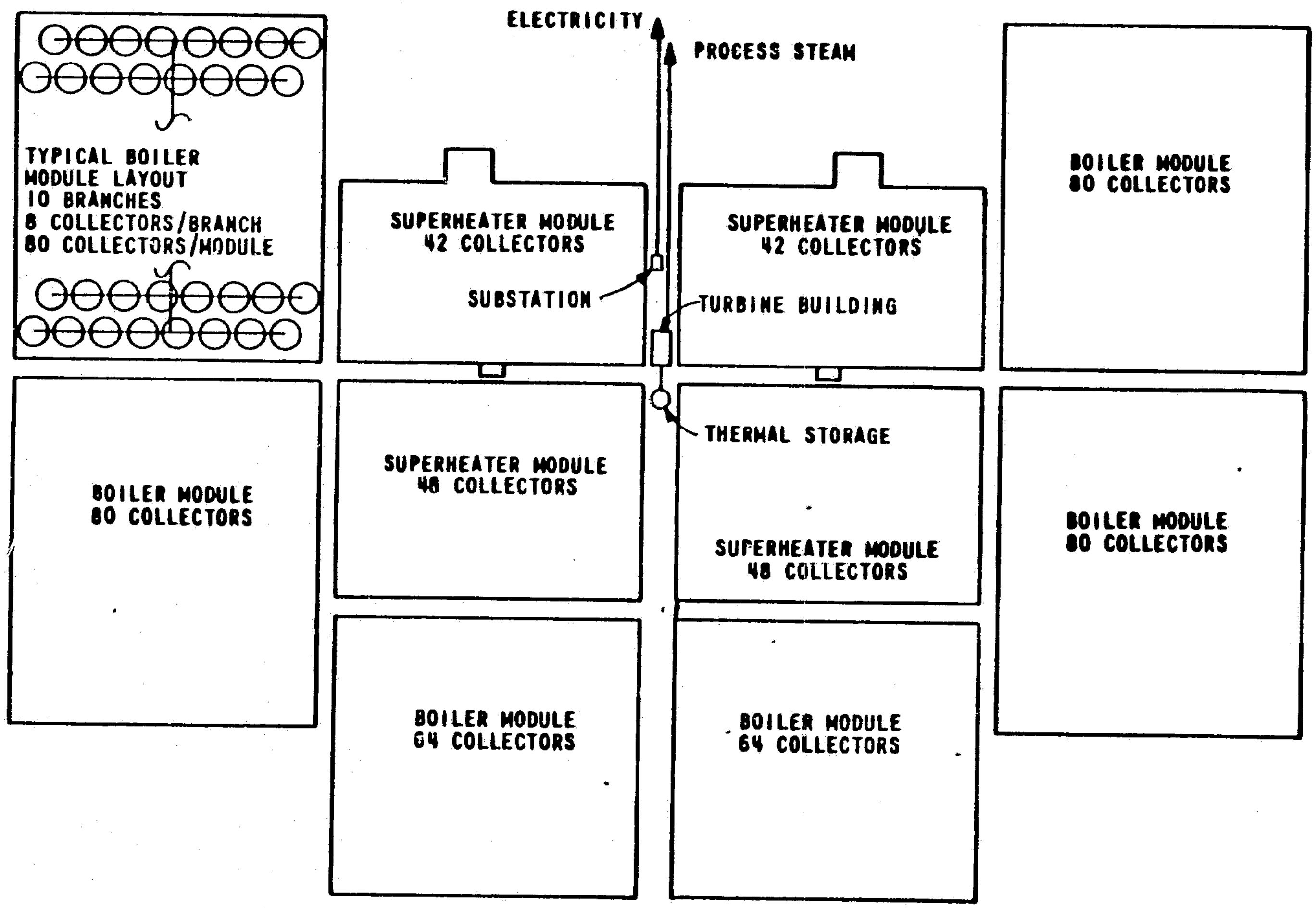

FIGURE 10.5-1. CASE 5 SYSTEM PLAN ARRANGEMENT

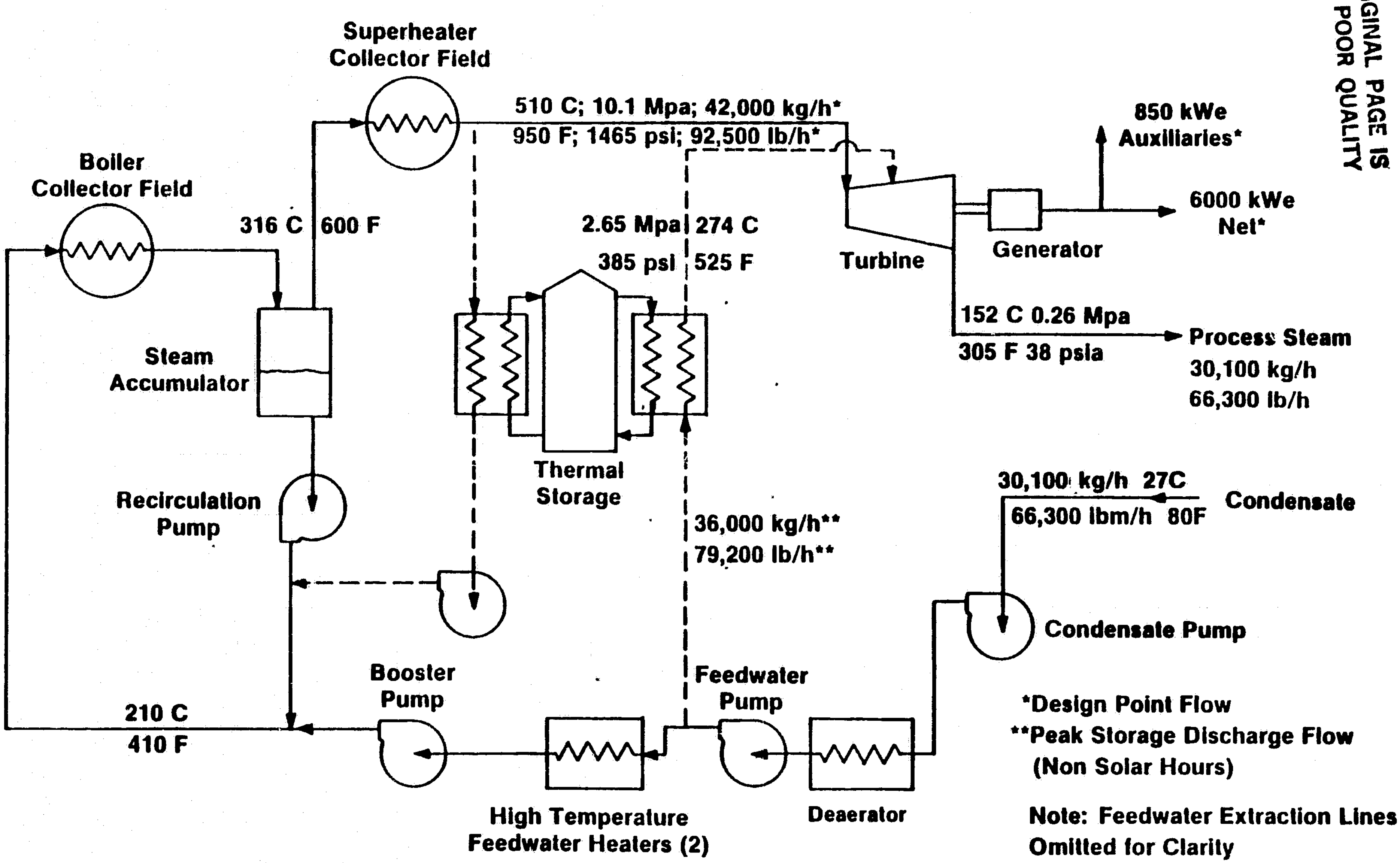

FIGURE 10.5-2 CASE 5 FUNCTIONAL FLOW DIAGRAM

TABLE 10.5-1 CASE 5 SUBSYSTEM DESIGN SUMMARIES

COLLECTOR SUBSYSTEM

Parameter	D. P. Value*
Concentrator (7)	
Dish Diameter, m (ft)	12 (39)
Effective Aperture Area, m^2 (ft^2)	111 (1,190)
Reflectivity	0.84
Shading Factor	0.94
Intercept Factor	0.96
Concentrator Effectiveness	0.74
Boiler Receiver**	
Aperture Diameter, m (ft)	0.25 (0.82)
Inlet Temperature, C (F)	210 (410)
Outlet Temperature, C (F)	316 (600)
Power Input, kWt (MBtu/h)	79.9 (0.273)
Power Output, kWt (MBtu/h)	77.8 (0.266)
Efficiency	0.97
Mass Flow Rate, kg/sec (lbm/sec)	0.047 (0.10)
Superheater Receiver**	
Aperture Diameter, m (ft)	0.25 (0.82)
Inlet Temperature	316 (600)
Outlet Temperature	510 (950)
Power Input, kWt (MBtu/h)	79.9 (0.273)
Power Output, kWt (MBtu/h)	76.0 (0.259)
Efficiency	0.95
Mass Flow Rate, kg/sec (lbm/sec)	0.11 (0.23)

*Design point value

**Receiver design characteristics have been synthesized for this application

ELECTRIC POWER GENERATION/PROCESS STEAM SUBSYSTEM

Parameter	D. P. Value
Cycle	Subcritical Rankine
Working Fluid	Water/Steam
Turbine Type	Dual Automatic Admission (Throttle and Second Level) Tandem Compound, Single Flow Noncondensing
Number of Feedwater Heaters	3 (Including deaerator)
Operation From Collector Field	
Gross electric output, kWe	6,850
Electric auxiliary load, kWe	850
Net electric output, kWe	6,000
Turbine throttle pressure, MPa (psig)	10.1 (1,465)
Turbine throttle temperature, C (F)	510 (950)
Thermal input, kWt (MBtu/h)	29,070 (99.21)
Turbine throttle flow rate, kg/h (lb/h)	42,000 (92,500)
Process steam flow rate, kg/h (lb/h)	30,100 (66,300)
Process steam temperature, C (F)	152 (305)
Process steam pressure, MPa (psia)	0.26 (38)
Process thermal input, kWt (MBtu)	22,200 (75.7)
Condensate temperature, C (F)	27 (80)
Operation From Thermal Storage	
Gross electric output, kWe	2,210
Electric auxiliary load, kWe	480
Net electric output, kWe	1,730
Turbine throttle pressure, MPa (psig)	1.14 (165)
Turbine throttle temperature, C (F)	274 (525)
Thermal input, kWt (MBtu/h)	24,400 (83.2)
Turbine throttle flow rate, kg/h (lb/h)	36,000 (79,200)
Process steam flow rate, kg/h (lb/h)	30,100 (66,300)

ELECTRIC POWER GENERATION/PROCESS STEAM SUBSYSTEM

Parameter	D. P. Value
Process steam temperature, C (F)	152 (305)
Process steam pressure, MPa (psia)	0.26 (38)
Process thermal input, kWt (MBtu/h)	22,200 (75.7)
Condensate temperature, C (F)	27 (80)

MASTER CONTROL SUBSYSTEM

- Central Control Mini-computer
- Main Control Panel
- Programmers Console
- CRT Displays.
- Printer.
- Interface Hardware.
  - -- Turbine Controller
  - -- Collector Controllers
  - -- Energy Transport Controllers
  - -- System Instrumentation

THERMAL ENERGY STORAGE SUBSYSTEM(5, 6)

Parameter	Value
Configuration	One-Tank, Parallel Storage
Medium	Oil/Rock
Storage Principle	Thermocline, sensible heat storage
Capacity, MWht (MBtu); h	126.2 (430); 5
Maximum Discharge Rate, MWt (MBtu/h)	25.2 (86.1)
Storage Temperature Range, C (F)	218-302 (425-575)
Discharge Temperature; Steam Side, C (F)	274 (525)
Discharge Pressure, Steam Side, MPa (psig)	2.65 (385)

THERMAL ENERGY TRANSPORT SUBSYSTEM

- General piping layout per Figure 10.4-1.
- Detailed piping layout similar to GE First Small Power System Experiment piping layout.(1)
  - -- Pneumatic control valve for each 8-collector branch
  - -- Automatic isolation of 8-collector branches
  - -- Manual isolation of each collector, half branch, and branch
- Superheated steam piping, valves, and fittings of A335 Grade P2, 1-1/2 Cr, 1/2 Mo alloy steel.
- Feedwater, saturated water/steam, and saturated steam piping, valves, and fittings of A106 Grade B carbon steel
- Insulated to reduce thermal losses to 5 per cent of rated power.
- All joints welded.
- Expansion loops provided to allow for thermal growth
- Per standard power plant practice, minimum pipe size used is 19.1 mm (3/4 inch) so that accidental breakage is avoided
- Condensate removed from pipelines via steam traps and condensate return lines.
- Availability of high temperature, high pressure flexible hoses assumed

BALANCE OF PLANT

- Buildings.
  - -- Turbine.
  - -- Central Control and Maintenance.
  - -- Warehouse (spare parts inventory).
- Maintenance Equipment.
  - -- Truck.
  - -- Crane.
  - -- Washing Vehicle.
  - -- Tools.
- Fire Protection System.
- Plant Lighting System.
- Roads
- Security Fence

is 24.4 MWt, with a resultant net electrical power of 1.73 MWe generated, and 22.2 MWt of process steam produced. These operating modes are illustrated on Figure 10.5-3a, which shows a clear March 21 design basis operating mode. Actual clear day operation would more likely have continuous generation of electricity and production of process steam.

Cloudy day operation would also include combined operation from solar and from storage. During those times of day when power from solar is less than the rated turbine input power (29.1 MWt), the combination of solar and storage input power would result in electrical generation between the solar-only level (6 MWe net) and the storage-only level (1.73 MWe net); process steam production stays essentially constant at 22.4 MWt. A typical cloudy day operation is depicted on Figure 10.5-3b.

To achieve the above operating modes, the various subsystems must fulfill certain functional requirements. Functional requirements for the collector subsystem, the thermal transport system, and the thermal storage subsystem are identical to those for Case 4 listed in Section 10.4.1, and will not be repeated here. The Electric Power Generation and Process Heat Subsystem has the following functional requirements.

- Generate up to a gross power of 6.85 MWe (6.0 MWe net) from solar, with process steam production up to 22.2 MWt (75.7 MBtu/h).
- Generate up to a gross power of 2.2 MWe (1.73 MWe net) from storage, with process steam production up to 22.2 MWt (75.7 MBtu/h), and
- Allow rapid change from generating via solar to generating via storage, vice versa, or via both storage and solar.

The Central Control System must fulfill the following functional requirements.

- Allow operator control of turbine output power and process steam flow and temperature.
- Send command signals to individual collectors to track, "defocus," or stow.

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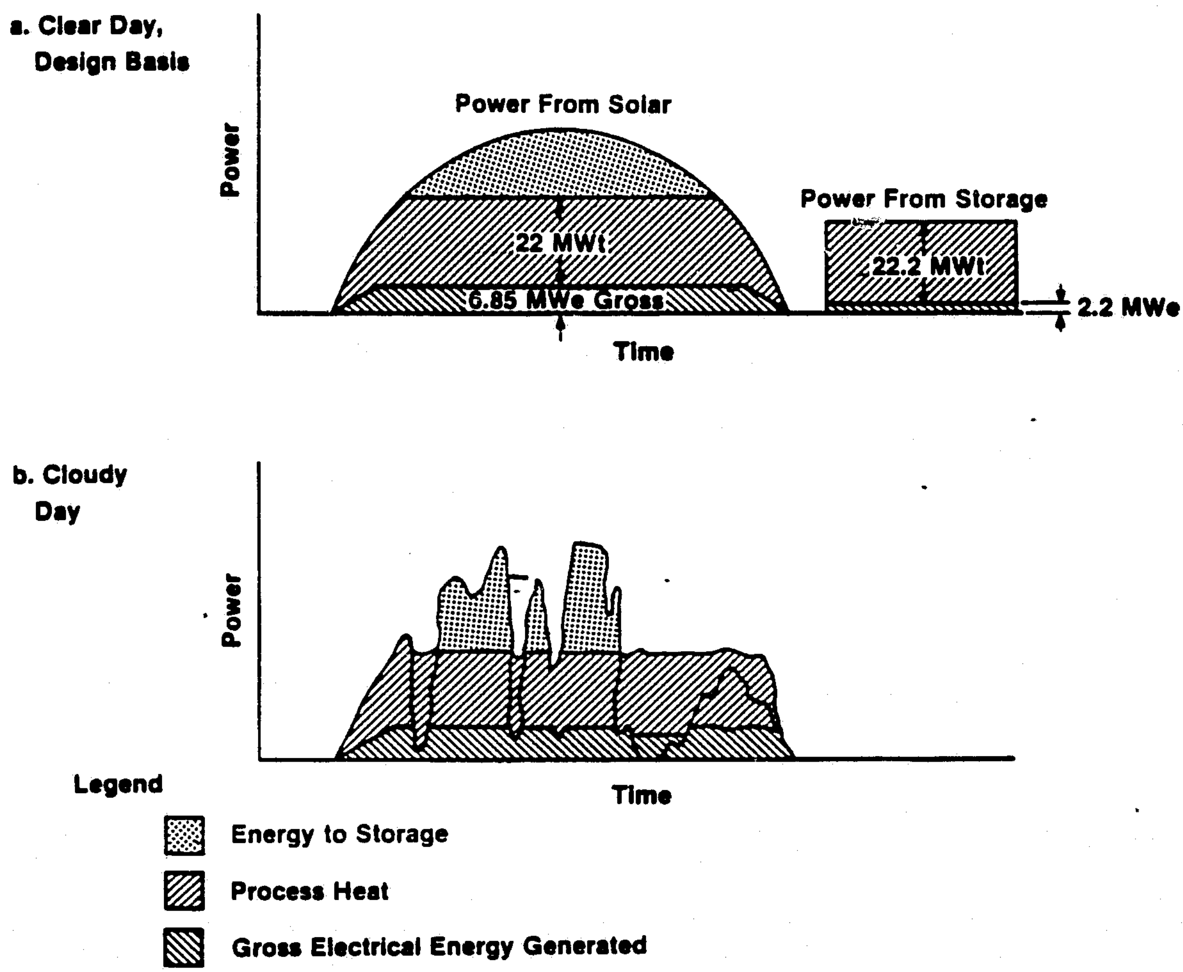

FIGURE 10.5-3 CASE 5 OPERATING MODES

- Monitor energy in thermal storage.
  - "Defocus" an appropriate number of collectors when storage is filled to capacity and the turbine is operating at rated power.
  - Command all collectors to track the sun when the system can utilize the full output of the collector system.
- Monitor system temperatures, pressures, and flows.
- Provide warnings and alarms for faulty operation.
  - High temperatures and pressures.
  - Indications of pipe ruptures.
- Provide built-in automatic system start-up and shut-down algorithms for the collector field.

Standards and Regulations. As with the Case 4 system, the Case 5 system design compiles with many laws, ordinances, codes, and standards. The previously given Table 10.4-3 lists applicable regulations.

10.5.1.2 Operational Requirements. The day-to-day operational factors of the Case 5 system are essentially the same as for the Case 4 system. Those requirements, regarding personnel, consumables, maintenance, and safety were discussed in Section 10.4.1.2. A difference in those operational factors is that personnel and maintenance equipment may be shared with the facility utilizing the process heat.

10.5.2 System Construction Considerations

Preliminary scheduling of the design, procurement, site preparation, and construction of the Case 5 system has been prepared. The total time period, from preliminary specifications through initial start-up, is estimated to be about 24 months. Figure 10.5-4 gives the construction schedule, detailing the various activity areas.

Assumptions used in preparing the schedule are as follows.

- A peak work force of 150 men is anticipated. This includes welders, dish erection crews, laborers, etc,
- An 8-hour day/20-day work month is assumed, and
- Seven four-man crews can assemble 28 dishes per week.

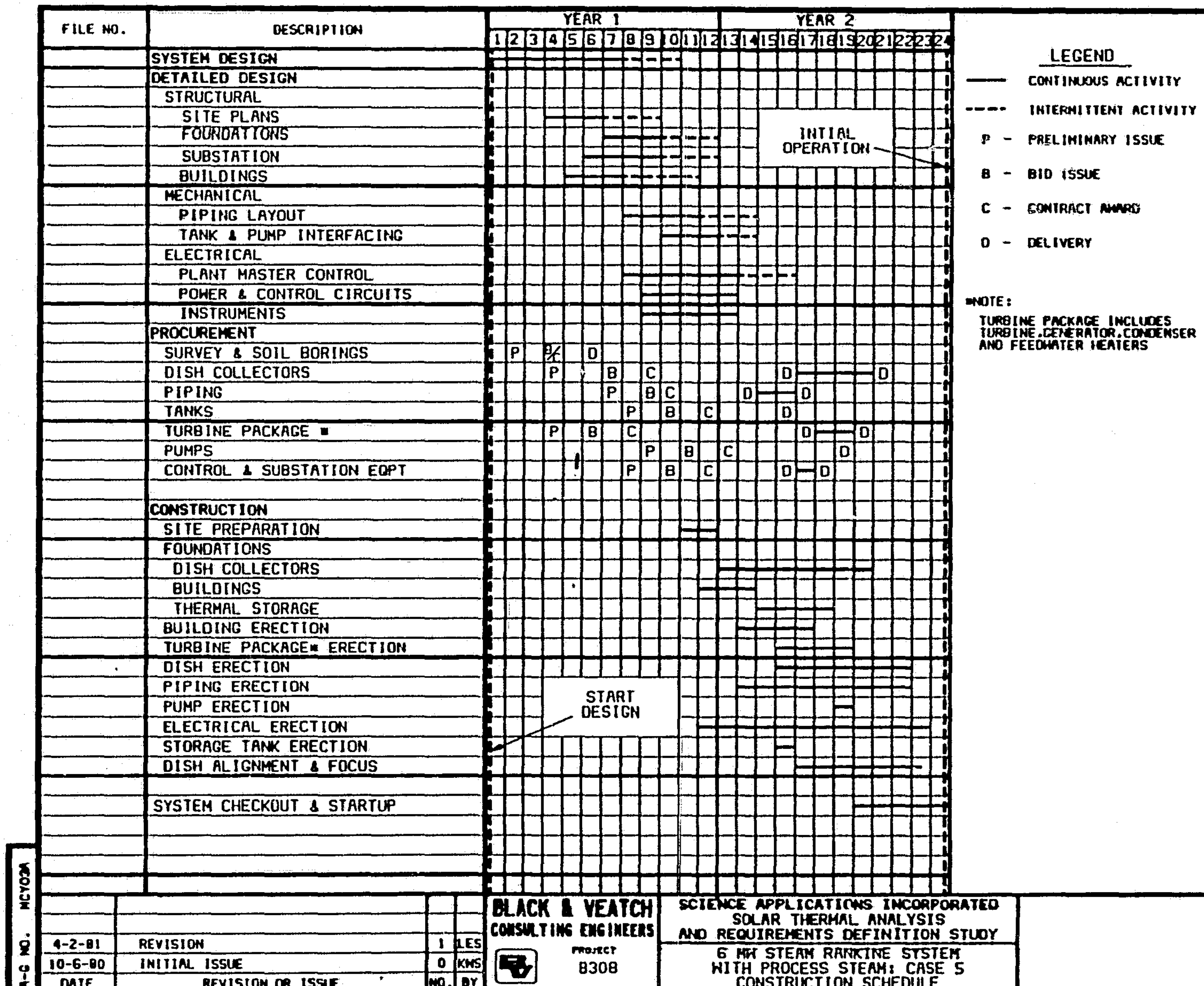

FIGURE 10.5-4 CASE 5 SYSTEM CONSTRUCTION SCHEDULE

10.5.3 System Cost Estimates

Capital cost estimates have been generated for the Case 5 system. A breakdown of the various subsystem costs, along with assumed contingencies and indirect costs are listed in Table 10.5-2; estimated operation and maintenance costs are also included.

The bases for the various subsystem costs are as follows.

- A concentrator cost of $\$100/m^2$ was used (FOB Tyler, Texas). This was in keeping with both the Task 1 data base,[7] and with DOE cost projections for large production levels.[8]
- Receiver costs of $60/kWe were used, assuming a solar multiple of 1.0, and a turbine generator efficiency of 0.3 for the costing exercise.[7, 8]
- Thermal storage costs were based on adaptations of costs for similar systems/components in the McDonnell Douglas Central Receiver 10 MWe Pilot Plant.[5]
- Other system costs were developed by the B&V cost estimating group from vendor information, B&V experience, and other published projects, based on first level material take-offs developed for the system design.
- Operation and maintenance costs are based on estimates from prior B&V solar projects, as well as published O&M projections for other projects.

Total costs include contingencies and indirects; indirect costs include engineering and construction management fees, administration and start-up costs, and AFDC.

10.5.4 Case 5 Sensitivity Study

The Case 5 sensitivity study examines the impact on cost and performance of reducing the system electrical output from 6 MWe net to 3 MWe net. It is assumed for this study that the process steam temperature and flow will remain the same as for the baseline 6 MWe system.

Table 10.5-3 summarizes the key performance and data for the baseline system (6 MWe) and the sensitivity study system (3 MWe). The 3 MWe system generates a lower electrical power level, but maintains the same

TABLE 10.5-2. CASE 5 SYSTEM CAPITAL COSTS

Item		Capital Cost* $
Land		287
Site Preparation		173
Collector Field		11,135
Concentrators	$7,096	
Receivers	1,005	
Concentrator/Receiver Installation	1,620	
Foundations (Installed)	1,414	
Thermal Energy Transport		9,928
Piping and Insulation	1,760	
Valves and Fittings	971	
Instrument Air System	29	
Installation-support foundations, labor, equipment	7,168	
Thermal Energy Storage		6,099
Media	412	
Equipment	4,863	
Installation	824	
Electric Power Generation		3,906
Turbine Generator, Condenser, etc.	3,170	
Steam Accumulators	290	
Installation	446	
Electrical Distribution		1,955
Material	993	
Installation	962	
Master Control		1,500
Balance of Plant		494
Subtotal		35,477
Contingencies (15 per cent)		5,322
Total Direct Costs		40,799
Indirects (32 per cent)		13,056
Total		53,855

Operations and Maintenance Cost: 810,000/year

*1,000's of 1980 dollars.

TABLE 10.5-3. CASE 5 SENSITIVITY STUDY: SYSTEM PERFORMANCE AND COSTS

System Performance	6 MWe System*	3 MWe System**
Design Point		
Power From Collector Field, MWt	46.1	46.1
Input Power To Turbine, MWt	29.1	25.9
Net Electrical Generation, MWe	6.0	3.0
Process Steam Heat, MWt	22.2	22.2
Storage Operation		
Input Power To Turbine, MWt	24.4	24.4
Net Electrical Generation, MWe	1.7	1.7
Process Steam Heat, MWt	22.2	22.2
Storage Capacity, MWht (h)	126 (5)	141 (5.8)
System Cost		
Land and Site Preparation	460	460
Collector Field	11,135	11,135
Thermal Energy Transport	9,928	9,928
Thermal Energy Storage	6,099	6,723
Electrical Power Generation	3,906	3,115
Electrical Distribution	1,955	1,905
Master Control	1,500	1,500
Balance of Plant	494	494
Subtotal	35,477	35,260
Contingencies and Indirects	18,378	18,265
Total	53,855	53,525

*Case 5 Baseline System.

**Case 5 Sensitivity Study System.

process steam output (study assumption); this results in more energy going to storage, requiring a 12 per cent increase in thermal storage capacity. Daily operation from storage is extended by about 48 minutes.

The cost for the 3 MWe system is about one per cent less than the 6 MWe system. Although the 3 MWe turbine cost is considerably less than the 6 MWe turbine cost, the larger storage capacity nearly balances the cost differences.

10.5.5 Case 5 References

1. General Electric Company, The First Small Power System Equipment, Phase I, Final Technical Report, NASA-CR-162417, May 1979.
2. Private communication to S. M. Clark, Black & Veatch, from H. E. Jones, Program Manager, General Electric, March 4, 1981.
3. J. J. Iannucci, Survey of U.S. Industrial Process Heat Usage Distributions, SAND80-8234, January 1981.
4. Jet Propulsion Laboratory, Proceedings of the First Semi-Annual Distributed Receiver Systems Program Review, DOE/JPL-1060-33, April 15, 1980.
5. McDonnell Douglas, Central Receiver Solar Thermal Power System, Phase I, CDRL Item 2, Pilot Plant Preliminary Design Report, SAN/1108-8/6, October 1977.
6. R. J. Copeland, M. E. Karpuk, and J. Ullman, A Preliminary Screening of Thermal Storage Concepts for Water/Steam and Organic Fluid Solar Thermal Receiver Systems, SERI/TR-631-647, April 1980.
7. Science Applications, Incorporated, Solar Thermal Plant Impact Analysis and Requirements Definition Study, Summary Report for Tasks 1, 2, and 3, JPL Contract # 955238, September 7, 1979.
8. Private Communication to L. E. Stoddard, Black & Veatch from John Lucas, Jet Propulsion Laboratory, August 4, 1980.

10.6 CASE 6: NINE MWe STEAM RANKINE SYSTEM WITH ALTERNATE PIPE LAYOUT

The Case 6 system is defined to be the same as the Case 4 system except that a new piping layout is to be used. The purpose of Case 6, with its "revisit" of the Case 4 piping system, is to investigate possible ways to reduce the cost of piping. In Case 4 (as well as Cases 1 and 3 and in other central generation cases with extensive piping networks) the thermal energy transport system accounted for a significant portion of the overall system cost (27 per cent for Case 4). Cost competitiveness of such systems appears to depend on lowering such piping costs. Case 6 is a 9 MWe parabolic dish system, located near Phoenix, Arizona, and is part of a large investor-owned utility. Distinguishing features of the case definition are as follows:

- Concentrators are patterned after the General Electric Low Cost Concentrator,
- Electric power generation is by a single nine MWe steam turbine,
- Five hours of thermal storage are included,
- Thermal energy transport is by either pressurized water or steam, and
- A sensitivity study which evaluates the impact of changing the turbine inlet steam temperature.

The design of the system is based on a 1990 time frame.

10.6.1 System Description

The Case 6 system is identical to the Case 4 system in all respects, except for the layout of the plant and details of the thermal energy transport subsystem. The collector field covers 38 hectares (95 acres), and consists of 448 steam boiler collectors and 180 superheater collectors. Wet saturated steam from the boiler field is collected in a steam accumulator; dry saturated steam is transported to the superheater field section, while saturated water is recirculated to the boiler field section. The system uses a parallel oil/rock thermocline storage concept. A functional flow diagram for the system is shown on Figure 10.6-1.

In devising a piping layout which might reduce the cost of the Case 4 thermal energy transport subsystem, several facets of the subsystem

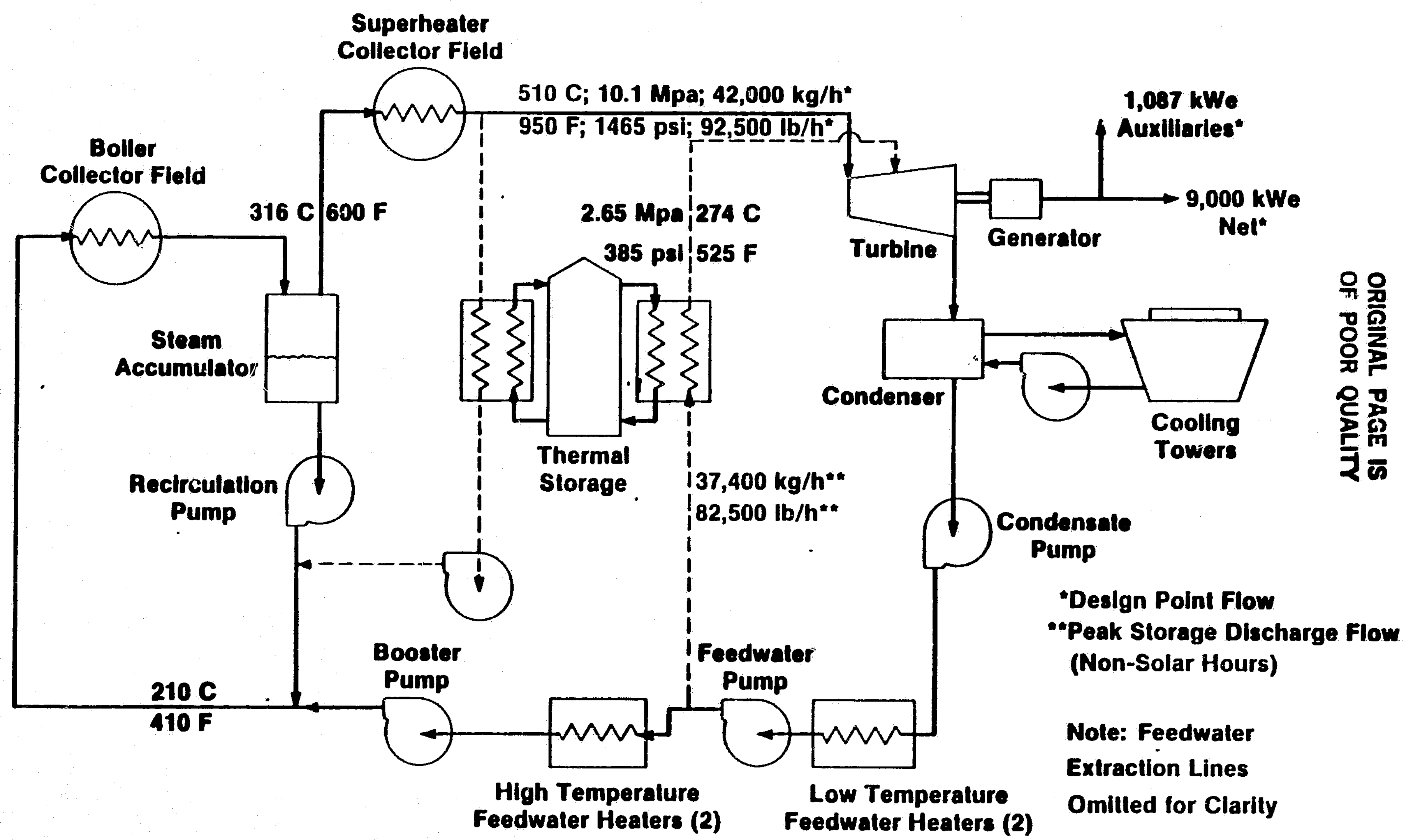

FIGURE 10.6-1 CASE 6 SYSTEM FUNCTIONAL FLOW DIGRAM (IDENTICAL TO CASE 4)

design were considered. The following are design considerations which were investigated; these areas will be discussed in the remainder of this section.

- Collector field and piping layout.
- Reduced number of valves.
- Use of ball joints instead of expansion loops.
- Pipe size reduction.
- Shop fabrication, when possible.

The first step in redesigning the thermal energy transport system was to change the collector field and piping layout in an attempt to reduce the length of pipe required. Improvements in the piping arrangement within each module were investigated. It was determined that the "T" branch arrangement used in Cases 1, 3, and 4, is better than other arrangements investigated; collectors are "picked up" every 21.3 m (70 ft), which is the shortest distance between collectors. Therefore any savings in piping must come from rearrangement of the overall field.

The Case 6 field arrangement, shown on Figure 10.6-2, reduces the overall amount of pipe used in Case 4 by 13 per cent; Figure 10.6-3 shows the Case 4 field arrangement for comparative purposes. The Case 4 system consisted of smaller modules (e.g., 80-collector boiler modules as opposed to 112-collector boiler modules in Case 6) and took on more of a circular field appearance. The Case 6 field reduces overall pipe length by reducing the length of headers and the main supply and return lines; amounts of branch piping are essentially unchanged from the Case 4 design. Because of the "tighter" configuration of Case 6, it was found that a single steam accumulator could be used (Case 4 used two accumulators). This further reduces the system cost because one large accumulator is less costly than two smaller accumulators.

A second consideration in reducing thermal energy transport system costs was to decrease the number of isolation valves; the number of control valves (one per eight-collector branch) has not been reduced. Case 4 utilized two manual isolation valves (one each for supply and return) per collector, two manual isolation valves per half branch (four collectors),

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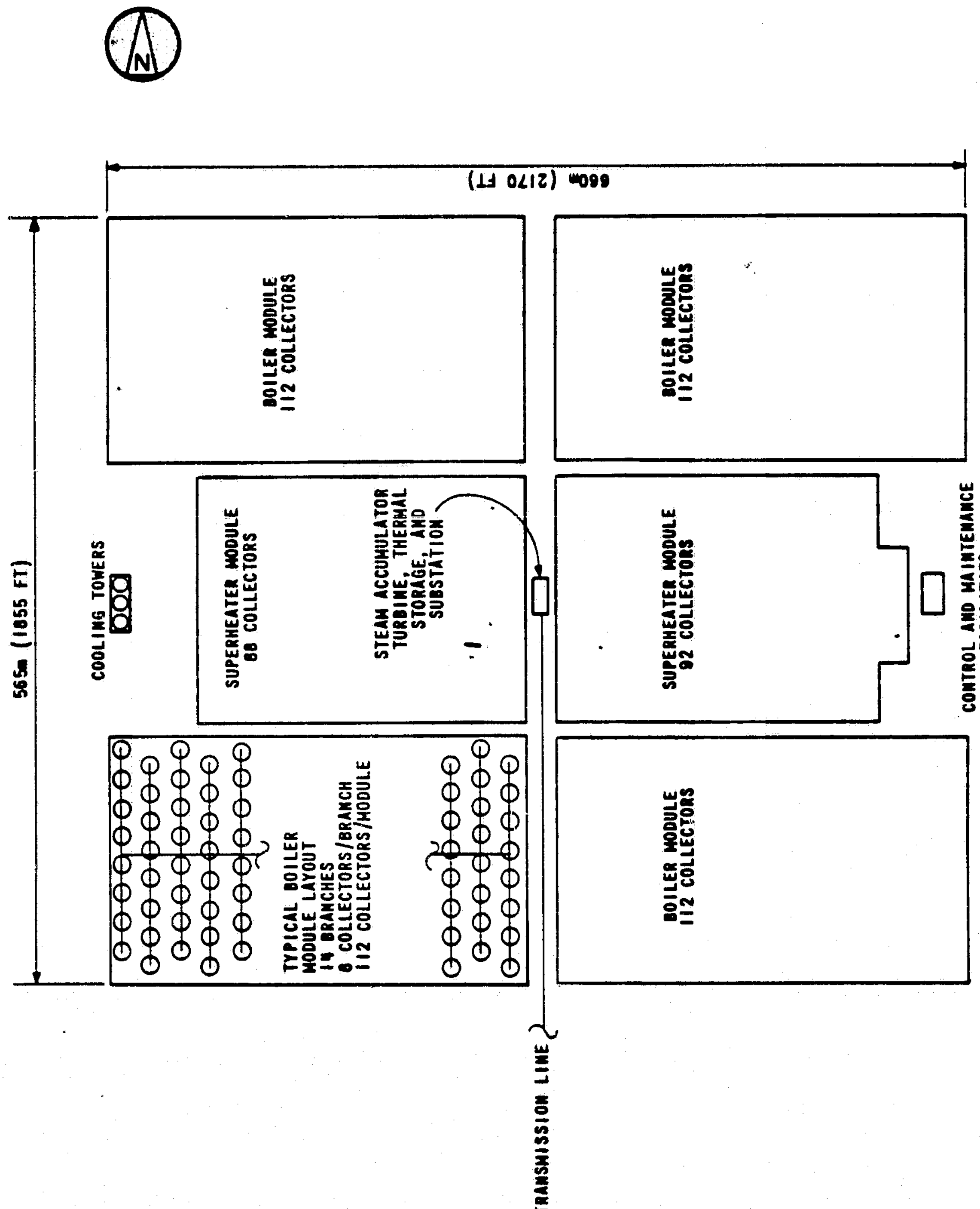

FIGURE 10.6-2. CASE 6 SYSTEM PLAN ARRANGEMENT

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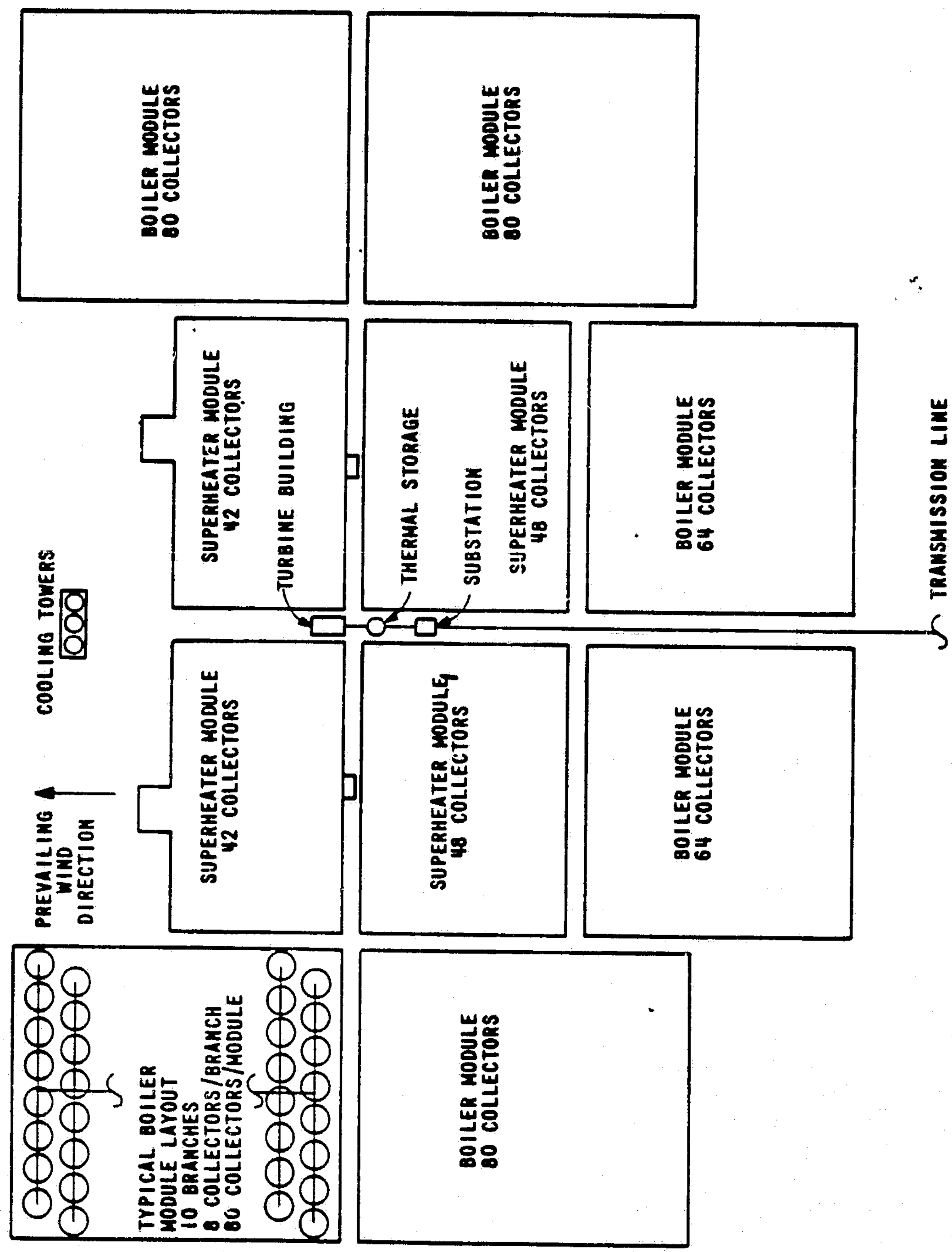

FIGURE 10.6-3. CASE 4 SYSTEM PLAN ARRANGEMENT

plus two manual and two automatic isolation valves per eight-collector branch. The Case 6 design has eliminated the manual isolation valves for each collector and half branch. The impact of eliminating these valves is a reduction in system capital cost; however, it requires that an entire eight-collector branch be isolated when a single collector requires maintenance. This constitutes a possible performance penalty.

A third consideration for the Case 6 piping network was to reduce piping cost by using a possibly more cost effective means of dealing with pipe expansion. The Case 4 system utilized expansion loops, adding 20 per cent to the total length of pipe required. In Case 6, ball joints have been utilized rather than expansion loops for pipe sizes of 51 mm (2 inches) inner diameter or larger.[1] Ball joints are not considered practical for smaller pipe sizes; expansion loops were utilized for the small sizes. The possibility of using flexible hose connections for small pipe sizes was explored; however, no flexible hose capable of simultaneously handling the fluid temperatures and pressures has been identified. (Flexible hose which can handle the high temperature or the high pressure, but not both, has been identified.)[1] It is assumed that by 1990, the flexible hose necessary for collector connections will be available; however, it is anticipated that the stringent demands of high temperature, high pressure construction will result in costs which will be prohibitive for extensive use in dealing with pipe expansion.

A fourth cost reduction consideration is the possible reduction of branch and branch-to-collector connection piping. For example, branch-to-collector feedwater connections of 9.5 mm (3/8 inch) id, Schedule 40 piping would be acceptable for the fluid flow rates, temperatures, and pressures per the ANSI B31-1 power piping code. However, the use of piping of less than 19 mm (3/4 inch) id, Schedule 80 size is not considered good power plant design practice where accidental breakage might endanger personnel safety. In Case 4, the minimum pipe size used was 19 mm (3/4 inch) id, Schedule 80. In Case 6, use of smaller pipe size has been considered as a perturbation on the base line Case 6 design.

The final cost reducing consideration is the increased use of shop fabrication to reduce the high cost of field installation of piping. Studies have shown that shop fabrication has potential for significantly reducing pipe costs;[2] typically, the maximum savings achievable by using shop fabrication in power plant piping is about 30 per cent.* One barrier to the extensive use of shop fabrication in the Case 6 system is that a pipe-fitters union agreement presently mandates field fabrication of pipe sizes of 51 mm (2 inches) id or smaller, unless such installations are an integral part of a piece of equipment. Since a large portion of the Case 6 system piping is of small diameter, this union regulation could have a significant limiting impact on the potential of cost reduction by shop fabrication unless some means of altering the agreement were established. For larger diameter piping in the Case 6 system, shop fabrication can have limited impact. Much of the large diameter installation is in straight runs for which shop fabrication yields little advantage.

For the Case 6 system, a 10 per cent reduction in pipe installation labor costs is assumed. This 10 per cent reduction is based on possible onsite automation of small diameter pipe installation, and a limited amount of shop fabrication for larger pipe sizes.

10.6.1.1 System Design Requirements. Design requirements for the Case 6 system are essentially the same as for Case 4. The reader is referred to Section 10.4.1.1 for the discussion of those requirements. Design details for the individual subsystems are summarized in Table 10.6-1.

10.6.1.2 Operational Requirements. Operation of the Case 6 system is essentially the same as for Case 4. The reader is referred to Section 10.4.1.2 for a discussion of operational requirements.

10.6.2 System Construction Considerations

Scheduling for the design, procurement, site preparation, and construction of the Case 6 system is similar to that of the Case 4 system (refer to Figure 10.4-4); differences in pipe installation time due to shop fabrication techniques will result in a smaller pipe fitters work force. The

*Black & Veatch records of vendor quotes.

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TABLE 10.6-1. CASE 6 SUBSYSTEM DESIGN SUMMARIES

COLLECTOR SUBSYSTEM(3)

Parameter	D. P. Value*
Concentrator(5)	
Dish Diameter, m (ft)	12 (39)
Effective Aperture Area, m^2 (ft^2)	111 (1,190)
Reflectivity	0.84
Shading Factor	0.94
Intercept Factor	0.96
Concentrator Effectiveness	0.74
Boiler Receiver**	
Aperture Diameter, m (ft)	0.25 (0.82)
Inlet Temperature, C (F)	210 (410)
Outlet Temperature, C (F)	316 (600)
Power Input, kWt (MBtu/h)	79.9 (0.273)
Power Output, kWt (MBtu/h)	77.8 (0.266)
Efficiency	0.97
Mass Flow Rate, kg/sec (lbm/sec)	0.047 (0.10)
Superheater Receiver**	
Aperture Diameter, m (ft)	0.25 (0.82)
Inlet Temperature	316 (600)
Outlet Temperature	510 (950)
Power Input, kWt (MBtu/h)	79.9 (0.273)
Power Output, kWt (MBtu/h)	76.0 (0.259)
Efficiency	0.95
Mass Flow Rate, kg/sec (lbm/sec)	0.11 (0.23)

*Design point value.

**Receiver designs have been synthesized for this application.

ELECTRIC POWER GENERATION SUBSYSTEM(4)

Parameter	D. P. Value
Cycle	Subcritical Rankine
Working Fluid	Water/Steam
Turbine Type	Dual Automatic Admission (Throttle and Second Level) Tandem Compound, Single Flow Condensing
Number of Feedwater Heaters	4
Cycle Heat Rejection	Wet, Mechanical Draft Cooling Towers
Operation From Collector Field	
Gross electric output, kWe	10,087
Electric auxiliary load, kWe	1,087
Net electric output, kWe	9,000
Turbine throttle pressure, MPa (psig)	10.1 (1,465)
Turbine throttle temperature, C (F)	510 (950)
Gross cycle efficiency	0.347
Thermal input, kWt (MBtu/h)	29,070 (99.21)
Turbine throttle flow rate, kg/h (lb/h)	42,000 (92,500)
Operation From Thermal Storage	
Gross electric output, kWe	6,147
Electric auxiliary load, kWe	617
Net electric output, kWe	5,530
Turbine throttle pressure, MPa (psig)	2.65 (385)
Turbine throttle temperature, C (F)	274 (525)
Gross cycle efficiency	0.244
Thermal input, kWt (MBtu/h)	25,240 (86.13)
Turbine throttle flow rate, kg/h (lb/h)	37,400 (82,500)

THERMAL ENERGY STORAGE SUBSYSTEM(4, 5)

Parameter	Value
Configuration	One-Tank, Parallel Storage
Medium	Oil/Rock
Storage Principle	Thermocline, sensible heat storage
Capacity, MWht (MBtu); h	126.2 (430); 5
Maximum Discharge Rate, MWt (MBtu/h)	25.2 (86.1)
Storage Temperature Range, C (F)	218-302 (425-575)
Discharge Temperature; Steam Side, C (F)	274 (525)
Discharge Pressure; Steam Side, MPa (psig)	2.65 (385)

THERMAL ENERGY TRANSPORT SUBSYSTEM

- General piping layout as per Figure 10.6-2.
- Detailed piping layout similar to GE First Small Power System Experiment piping layout.(6)
- Superheated steam piping, valves, and fittings of A335 Grade P2, 1-1/2 Cr, 1/2 Mo alloy steel.
- Feedwater, saturated water/steam, and saturated steam piping, valves, and fittings of A106 Grade B carbon steel.
- Insulated to reduce thermal losses to 5 per cent of rated power.
- All joints welded.
- Expansion loops provided to allow for thermal growth of pipe sizes less than 51 mm (2 inches).
- Ball joints used to allow for thermal growth of pipe sizes greater than 51 mm (2 inches)
- For base line design, minimum pipe size of 19.1 mm (3/4 inch) used to prevent accidental breakage by plant staff. Alternate design allows use of smaller pipe sizes.
- Condensate removed from pipelines via steam traps and condensate return lines.

MASTER CONTROL SUBSYSTEM

- Central Control Mini-computer.
- Main Control Panel.
- Programmers Console.
- CRT Displays.
- Printer.
- Interface Hardware
  - -- Turbine Controller.
  - -- Collector Controllers.
  - -- Energy Transport Controllers.
  - -- System Instrumentation.

BALANCE OF PLANT

- Buildings.
  - -- Turbine.
  - -- Central Control and Maintenance.
  - -- Warehouse (spare parts inventory).
- Maintenance Equipment.
  - -- Truck.
  - -- Crane.
  - -- Washing Vehicle.
  - -- Tools.
- Fire Protection System.
- Plant Lighting System.
- Roads.
- Security Fence.

total time period, from preliminary specifications through initial start-up, is estimated to be about 24 months.

Assumptions used in preparing the schedule are as follows.

- A peak work force of about 100 men is anticipated. This includes welders, dish erection crews, laborers, etc,
- An 8-hour day/20-day work month is assumed, and
- Seven four-man crews and assemble 28 dishes per week.

10.6.3 System Cost Estimates

Capital cost estimates for the Case 6 system are somewhat lower than for the Case 4 system. A breakdown of the various subsystem costs, along with assumed contingencies and indirect costs are listed in Table 10.6-2; estimated operation and maintenance costs are also included.

The bases for the various subsystem costs are as follows.

- A concentrator cost of $\$100/m^2$ was used (FOB Tyler, Texas). This was in keeping with both the Task 1 data base,[7] and with DOE cost projections for large production levels.[8]
- Receiver costs of \$60/kWe were used, assuming a solar multiple of 1.0, and a turbine generator efficiency of 0.3 for the costing exercise.[7, 8]
- Electric power generation and thermal storage costs were based on adaptations of costs for similar systems/components in the McDonnell Douglas Central Receiver 10 MWe Pilot Plant.[4]
- Other system costs were developed by the B&V cost estimating group from vendor information, B&V experience, and other published projects, based on first level material take-offs developed for the system design. Possible savings in pipe installation by using shop fabrication techniques were considered.
- Operation and maintenance costs are based on estimates from prior B&V solar projects, as well as published O&M projections for other projects.

A detailed breakdown of the thermal energy transport system capital costs are shown in Table 10.6-3. This table gives the Case 4 thermal energy transport subsystem costs, provided as reference data, the Case 6

TABLE 10.6-2. CASE 6 COST SUMMARY

Item		Capital Cost* $
Land		238
Site Preparation		143
Collector Field		11,135
Concentrators	$7,096	
Receivers	1,005	
Concentrator/Receiver Installation	1,620	
Foundations (Installed)	1,414	
Thermal Energy Transport		7,695
Piping and Insulation	1,435	
Valves and Fittings	651	
Instrument Air Piping	27	
Installation-support foundations, labor, equipment	5,582	
Thermal Energy Storage		6,099
Media	412	
Equipment	4,863	
Installation	824	
Electric Power Generation		5,816
Turbine Generator, Condenser, etc.	3,905	
Heat Rejection	984	
Steam Accumulator	260	
Installation	667	
Electrical Distribution		1,955
Material		993
Installation		962
Master Control		1,500
Balance of Plant		451
Subtotal		36,987
Contingencies (15 per cent)		5,548
Total Direct Costs		42,535
Indirects (32 per cent)		13,611
Total		56,146

Operations and Maintenance Cost: $840,000/year

*1,000's of 1980 dollars.

**Includes shipping costs per G. E. shipment packaging criteria.(12)

TABLE 10.6-3. PIPING COST BREAKDOWN

Item	Case 4			Case 6, Base Line			Case 6, Small Pipe*		
	Material	Labor	Total	Material	Labor	Total	Material	Labor	Total
Feedwater Piping**	341	1,172	1,513	302	914	1,216	233	914	1,147
Saturated Water/Steam Piping**	632	1,464	2,096	566	1,110	1,676	559	1,108	1,667
Saturated Steam Piping**	187	504	691	160	404	564	157	403	560
Superheated Steam Piping**	465	1,151	1,616	279	694	973	264	694	958
Condensate Return Pipe, Traps**	130	188	318	128	173	301	128	173	301
Valves and Fittings***	971	--	971	651	--	651	650	--	650
Instrument Air Piping	29	143	172	27	122	149	27	122	149
Pipe Support Stands, Foundations	1,386	1,155	2,541	1,181	984	2,165	1,599	1,333	2,932
	4,141	5,777	9,918	3,294	4,401	7,695	3,617	4,747	8,364

*Case 6 Small Pipe System allows the use of pipe sizes smaller than 19 mm (3/4 in.) Schedule 80.

**Includes insulation and ball joints (for Case 6).

***Valve installation included in pipe installation.

base line system (no pipe sizes smaller than 1.9 mm (3/4 inch) id, Schedule 80), and the perturbation of Case 6 where smaller pipe sizes are allowed. It can be seen that the cost gains obtained by using smaller pipe sizes are offset by the need for closer spaced pipe supports so that the system with smaller pipe sizes actually costs more than the base line system.

10.6.4 Case 6 References

1. Private Communication to S. M. Clark, Black & Veatch, from Rob Lund, Representative for Barco and for Flexonic Hoses, Reintjes, and Hiter, March 27, 1981.
2. J. Biddle, W. Revere, and T. Fujita, "Low-Cost Thermal Transport Piping Networks for Solar Industrial Process Heat Applications," presented at the 5th Annual Solar Industrial Process Heat Conference, Houston, Texas, December 16-19, 1980.
3. Jet Propulsion Laboratory, Proceedings of the First Semi-Annual Distributed Receiver Systems Program Review, DOE/JPL-1060-33, April 15, 1980.
4. McDonnel Douglas, Central Receiver Solar Thermal Power System, Phase I, CDRL Item 2, Pilot Plant Preliminary Design Report, SAN/1108-8/6, October 1977.
5. R. J. Copeland, M. E. Karpuk, and J. Ullman, A Preliminary Screening of Thermal Storage Concepts for Water/Steam and Organic Fluid Solar Thermal Receiver Systems, SERI/TR-631-647, April, 1980.
6. General Electric Company, The First Small Power System Experiment, Phase I, Final Technical Report, NASA-CR-162417, May, 1979.
7. Science Applications, Incorporated, Solar Thermal/Plant Impact Analysis and Requirements, Definition Study, Summary Report for Tasks 1, 2, and 3, JPL Contract No. 955238, September, 1979.
8. Private Communication to L. E. Stoddard, Black & Veatch, from John Lucas, Jet Propulsion Laboratory, August 4, 1980.

10.7 CASE 7: DISTRIBUTED GENERATION WITH A STIRLING ENGINE AND BATTERY STORAGE

The Case 7 system is defined to be a 10 MWe dish system with dispersed generation via Stirling engines. Features which define the case are as follows.

- Concentrators are patterned after the GE Low Cost Concentrator.
- Generation is by Stirling engines mounted on each collector.
- Electrical storage (batteries) is sized to deliver rated power (10 MWe) for three hours based on 100 per cent discharge.
- The sensitivity study examines impacts of changes in subsystem costs, subsystem efficiencies, subsystem sizes, site variables, and installation variables (it is similar to the sensitivity study of Case 1).
- The system is located at Barstow, California, and is considered connected to the Southern California Edison grid.
- The design time frame is 1990.

The Case 7 system design is based on performance for a clear March 21 day, with a peak insolation of 950 watts/m^2 (301 Btu/h/ft^2). It is sized such that the plant provides a 10 MWe net output during the day, and sufficient electrical energy is stored to allow three hours of power delivery from storage at 10 MWe. This system size provides a 10 MWe output capability for about 13 hours per day based on March 21 conditions. It has a solar multiple (design point net electrical power generated divided by net power delivered to the grid) of 1.7.

10.7.1 System Description

The Case 7 design has the following key characteristics; the rationale for selecting these characteristics is presented on Table 10.7-1.

- The Stirling engine, patterned on the United Stirling 4-95 engine, uses helium as a working fluid, with the outer tube wall at 810 C (1,490 F).[1]
- The solar receiver is considered to be similar to the Non-Heat-Pipe Receiver[5] being developed by Fairchild Stratos Division except that hybrid capabilities are omitted.

TABLE 10.7-1. KEY DESIGN DECISIONS FOR CASE 7

Decision	Favoring Rationale	Opposing Rationale
Double acting, 4 cylinder Stirling engine.[1]	Engine being developed with test operation exceeding 13,000 hours.	None known.
Helium working fluid rather than hydrogen.[1]	Engines and receivers currently being developed for solar operation use helium.	Using hydrogen would result in a 1 percentage point increase in cycle efficiency.
Engine outer tube temperature of 810 C (1,490 F)[1]	Engine currently being developed has 5,800 hours of operation at 820 C (1,510 F).	Use of ceramics could push temperatures up to 1,100 C (2,012 F) with cycle efficiencies increased to about 49 per cent from 40 per cent.
AC generation synchronized with the utility grid.	Rectification and inversion losses and capital costs (~$75/kWe) are eliminated for that portion of plant output which is not stored electrically.	Significantly increased complexity of control system for synchronized, constant speed (1800 rpm) operation.
Zinc chloride battery energy storage.[2,3,4]	Long battery module lifetime at deep cycling (3,000-5,000 cycles). Semi-mature production anticipated within 1990 time frame. Life cycle costing appears more favorable than alternatives.	Flowing electrolyte system adds complexity.

- Power collection within the field is 3 phase, 480 vac; each unit is synchronized with the utility grid.
- The energy storage uses an advanced zinc chloride battery system patterned after the Energy Development Associates Mark 4 System.[2, 3, 4, 6] Batteries are at a single location on the perimeter of the collector field.

10.7.1.1 System Design Requirements. This subsection presents specific design requirements for the Case 7 baseline system. Topics addressed include

- Site conditions,
- Site arrangement,
- System design point requirements,
- System functional requirements, and
- Standards and regulations.

Site Conditions. The Case 7 system is located at a site near Barstow, California. It is assumed for this study that the site selection can be made to minimize site preparation, and that plant support factors (roads, etc.) are nearby. Table 10.7-2 lists the assumed Case 7 site conditions.

Site Arrangement. The physical layout for the Case 7 system is illustrated on Figure 10.7-1. The collector field, which covers about 32 hectares (80 acres), contains 675 collectors. The field is divided into nine electrical power collection modules. The three phase 480 vac power generated by each collector unit is transmitted to the center of the collection module, where it is stepped up to 4,160 V (the plant output voltage) for transmission to the plant switchyard at the perimeter of the field. Battery storage (with power conversion equipment) is also located at the field perimeter, as are the plant control, administration, and maintenance facilities.

System Design Point Requirements. The baseline system was designed to provide rated power (10 MWe net) at noon, March 21, while providing about 7 MWe to storage. Figure 10.7-2 shows a functional configuration of the system. Design details for the individual subsystems, Collector/Receiver, Electric Power Generation and Energy Storage System, are listed on Table 10.7-3.

TABLE 10.7-2. CASE 7 SITE CONDITIONS (Barstow, California)[7,8]

Environmental Conditions

- Maximum Temperature: 46 C (115 F).
- Minimum Temperature: -7 C (20 F).
- Annual Average Temperature: 18 C (65 F).
- Maximum Windspeed: 74 km/h (46 mph).
- Average Windspeed: 10 km/h (6.4 mph).
- Prevailing Wind Direction: Northwest.
- Average Annual Precipitation: 14 cm (5.7 in).
- Average Daily Direct Normal Insolation: 7.5 kWh/m^2/day (2,400 Btu/ft^2)day).

Assumed Terrain

- Relatively flat, level land area.
- Plant site has few, if any, trees.
- Competent bearing strata near surface.
- Seismic Zone: 3.

Note: Climatological data is based on recorded data for Bakersfield, California.

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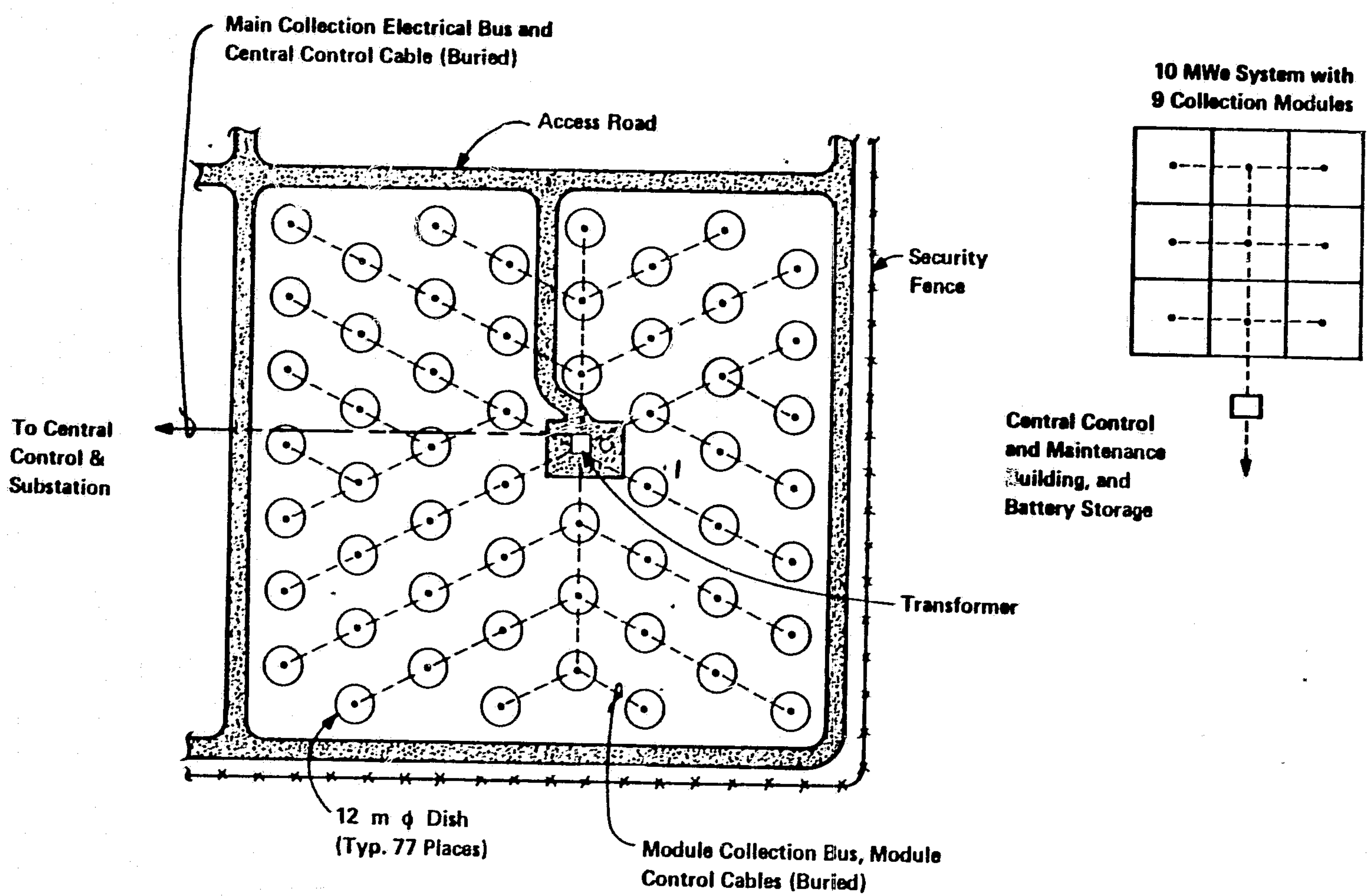

FIGURE 10.7-1 CASE 7 COLLECTION MODULE PLAN ARRANGEMENT

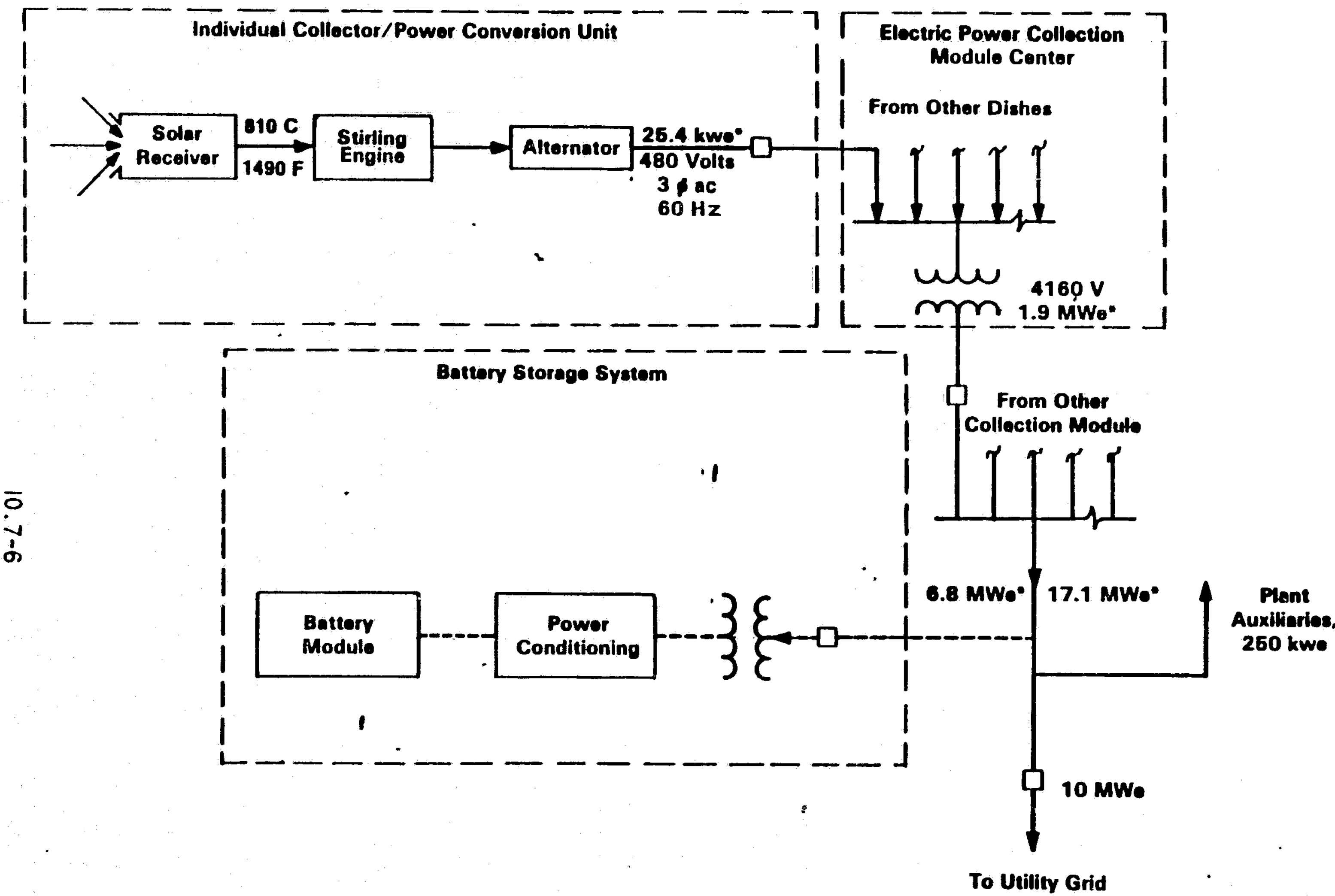

FIGURE 10.7-2 CASE 7 FUNCTIONAL FLOW DIAGRAM

TABLE 10.7-3. CASE 7 SUBSYSTEM DESIGN SUMMARIES

COLLECTOR SUBSYSTEM[9,5]

Parameter	D. P. Value *
Concentrator	
Dish Diameter, m (ft)	12 (39)
Effective Aperture Area, m^2 (ft^2)	111 (1,190)
Reflectivity	0.84
Shading Factor	0.94
Intercept Factor	0.96
Concentrator Effectiveness	0.74
Stirling Receiver	
Outer Diameter, m (ft)	0.70 (2.3)
Aperture Diameter, m (ft)	0.24 (0.79)
Inlet Temperature, C (F)	610 C (1,130)
Working Fluid Temperature, C (F)	810 (1,490)
Power Input, kWt (MBtu/h)	79.9 (0.273)
Power Output, kWt (MBtu/h)	69.6 (0.238)
Efficiency	0.87

*Design point value.

ELECTRIC POWER GENERATION SUBSYSTEM[1,10]

Parameter	D. P. Value*
Cycle	Stirling
Engine Type	Double acting, 4 cylinder
Working Fluid	Helium
Outer Tube Temperature, C (F)	810 (1,490)
Helium Mean Pressure MPa (psia)	15 (2,200)
Thermal Input, kWt (MBtu/h)	69.6 (0.238)
Cycle Efficiency	0.40
Shaft Output Power, kWm (hp)	27.8 (37.3)
Shaft Speed, rpm	1,800
Alternator Efficiency	0.94
Electric Accessory Load, kWe	0.7
Collector Module Electric Power, kWe	25.4

*Design point value.

Energy Storage Subsystem[2,3,4,6]

- Zinc chloride battery system patterned after one module of the Energy Development Associates Mark 4 system.
- Storage capacity of 30.75 MWhe deliverable energy to the electrical distribution substation.
- Maximum charge rate of 10.25 MWe.
- Power output is 10.25 MWe (10.0 MWe deliverable to the grid).
- In/out (ac to storage to ac) efficiency of 65 per cent.
- System includes:
  - -- Battery modules.
  - -- Rack assemblies.
  - -- Refrigeration and cooling systems.
  - -- Battery auxiliaries circuitry.
  - -- Power conditioning equipment.
  - -- Controls.

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Electrical Energy Transport Subsystem

- General electrical layout as per Figure 10.7-1.
  - -- Generation at 480 V, 3 phase ac.
  - -- Nine collection modules.
  - -- Step up to 4,160 V at each collection center.
- Direct buried cable wi[illegible] EPR insulation and CSP Jacket.
- Connection to Battery Storage System at the field perimeter.
- Switchgear and lighting protection.

Master Control Subsystem

- Central Control Mini-computer.
- Main Control Panel.
- Programmers Console.
- CRT Displays.
- Printer.
- Interface Hardware.
  - -- Engine Controllers.
  - -- Collector Controllers.
  - -- Energy Transport Controllers.
  - -- System Instrumentation.

Balance of Plant

- Buildings.
  - -- Central Control and Maintenance.
  - -- Warehouse (spare parts inventory).
- Maintenance Equipment.
  - -- Truck.
  - -- Crane.
  - -- Washing Vehicle.
  - -- Tools.
- Fire Protection System.
- Plant Lighting System.
- Roads.
- Security Fence.

System Functional Requirements. The previous section on system design point characteristics has described the Case 7 configuration along with design point temperatures, efficiencies, and powers. This section identifies various system operating modes and the functional roles of the subsystems in achieving those modes.

The overall system has been designed such that on a clear March 21 day the net plant power output during solar operation is 10 MWe, while battery storage with a 3 hour (30 MWHR net) at 10 MWe capacity is filled. The operating strategy for that design is shown on Figure 10.7-3a. Although the plant is rated at 10 MWe in accordance with this operating strategy, the electrical distribution network is capable of allowing operation with no storage as shown on Figure 10.7-3b; a peak plant power output of 17.1 MWe is achievable at noon with this strategy. The daily plant energy output when operating without storage is somewhat higher than when storage is used due to losses in rectification, storage, and inversion (a 65 per cent efficient in/out process).

The capability to operate the plant at greater than 10 MWe output power has an advantage over the previously defined thermal storage systems (Cases 1 and 3 through 6) in that no energy need be lost through defocusing on clear summer days when the storage capacity is filled. As shown on Figure 10.7-3c, the energy generated after storage is filled can be delivered to the grid. A more likely summer operating strategy is as shown on Figure 10.7-3d where the plant power output during solar hours is raised somewhat above 10 MWe; power output from storage is limited to 10 MWe. Typical cloudy day plant operation is shown on Figure 10.7-3e.

Start-up of the system consists of several steps. First, each collector is commanded to begin tracking the sun. As the receiver temperature approaches the engine start-up threshold, an electrical starting motor begins cranking the engine. As the thermal heat input to the engine increases, the speed increases until the synchronization speed is reached (each engine has a microprocessor which monitors and controls engine speed). At this point, the engine/alternator is brought into synchronization, and the switch to the system electrical network is closed. Shutdown

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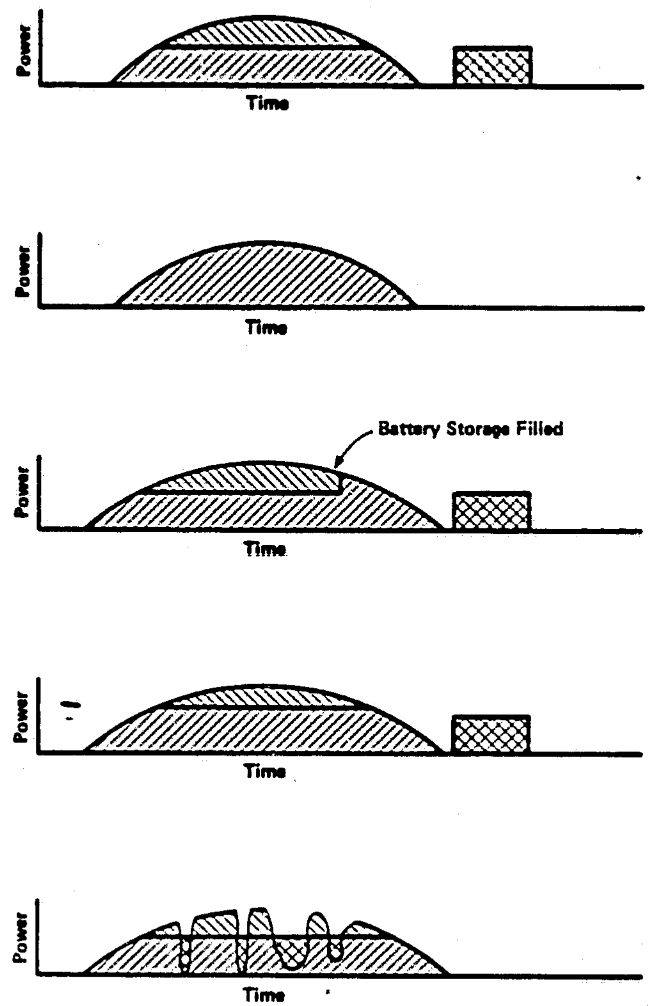
(a) March 21,
Design Basis

(b) March 21,
No Storage Used

(c) Clear Summer Day,
"10 MWe" Operation

(d) Clear Summer Day,
Above 10MWe Operation

(e) Cloudy Day



Energy delivered to grid directly from solar.

Energy delivered to battery storage.

Energy delivered to grid from battery storage.

FIGURE 10.7-3 CASE 7 OPERATING MODES

essentially reverses this process. As thermal heat input to the engine decreases (due either to lack of insolation or to defocusing of the dish), a threshold is reached where the engine can no longer maintain synchronization speed. At this time, the switch to the electrical network is opened and the engine is shut down.

In achieving the above operating modes, the <u>Collector Subsystem</u> must fulfill the following functional requirements.

- Two axis tracking of the sun.
- Deliver up to 70 kW_t (0.24 mBtu/hr) to each Stirling engine.
- Operate in winds up to 50 km/hr (31 mph).
- Slew to stow in winds up to 80 km/hr (50 mph).
- Survive stowed in winds up to 120 km/hr (75 mph).
- Survive 0.35 g lateral seismic load.*

The <u>Power Conversion Unit</u>, including the Stirling engine, alternator, and heat rejection radiator, must fulfill the following functional requirements.

- Generate up to 25.4 kWe per dish unit (480 V, 3 phase ac).
- Remain synchronized with the utility grid at a nominal 1,800 rpm.

The <u>Energy Transport</u> system must fulfill the following functional requirements.

- Collect up to 1.9 MWe at at 480 V, 3 phase ac at each collection center (9 total).
- Transmit up to 10.25 MWe from the nine collection centers to the battery storage and utility grid connections at the perimeter of the field.
- Step up to 4,160 volts ac for transmission to the overall system output bus.

*The 0.35 g lateral seismic load survival is based on a requirement by Sandia Laboratories for design survival capability for heliostats in the Advanced Water/Steam Receiver Project located at Barstow(11). The GE concentrator design is stated to have .25 g survival capabilities; because it is thought that wind loading (rather than seismic loading) dominates the design,(12) the concentrator dish is not likely to require any significant changes to survive the 0.35 g seismic load.

- Have line losses of no more than 0.5 MWe (3 per cent of total power generated).
- Provide switching for isolation of collector modules and individual collectors.
- Provide lightning protection.

The Energy Storage Subsystem must fulfill the following functional requirements.

- Provide capacity for storing 30.75 MWhe energy output (i.e., net energy after inversion to ac).
- Have an average in-to-out efficiency (ac energy out divided by ac energy in) of 65 per cent.[2, 3]
- Allow charging at rates of up to 17.1 MWe ac input.
- Allow discharge at rates of up to 10.25 MWe ac output.
- Interface battery control/master control to allow operator control of storage charge/discharge strategy.

The Master Control System must fulfill the following functional requirements.

- Send command signals to individual collectors to track, "defocus," or stow.
- Coordinate solar system start-up.
  - Commence collector tracking of the sun.
  - Initiate engine start-up.
  - Effect synchronization of the engine/alternator with the grid.
- Coordinate solar system shutdown.
  - Sense engine inability to maintain synchronization.
  - Disconnect engine/alternator from the grid.
  - Cease tracking of sun.
- Interface with battery storage system controls to allow operator control of storage charge/discharge strategy.
- Provide warnings and alarms for faulty operation.

Standards and Regulations. The Case 7 system design is responsive to a number of laws, ordinances, codes, and standards. A listing of applicable codes was given previously in Section 10.1.1.1.

10.7.1.2 Operational Characteristics. Four areas of operational characteristics for the Case 7 System have been identified. These topics are as follows.

- Personnel.
- Consumables.
- Maintenance.
- Safety.

An operating and maintenance staff of seven people is anticipated. This staff would include three plant operators with duty hours arranged so as to cover the average system operation 16 hours per day, 7 days per week. On cloudy days, operators would perform inspections and routine maintenance. The four remaining workers would perform maintenance duties full time.

Consumables for the system will be primarily concentrator washing solution. Washing solution consumption is estimated to be about 61,000 liters (17,000 gallons) per month; the solution makeup is primarily water. Other system consumables have low annual consumption rates.

The primary maintenance activity will be washing of concentrators. Using a special washing vehicle, the monthly washing process is anticipated to take about 15 minutes per concentrator, adding up to about 21 man-days per month. Other routine maintenance activities will include annual inspections of electrical equipment (switchgear, tranformer oil level, etc), concentrator reflective surfaces, etc.

Projected equipment overhaul includes refurbishing of concentrator reflector surfaces after about 10 years of service.(13) It is anticipated that gore panels would be replaced with new or refurbished panels, and that the old panels would be returned to the manufacturer. This process could be staggered over a long period of time such that plant output would not be significantly impacted.

Scheduled Stirling engine maintenance includes annual replacement of piston rings, and engine overhaul after 30,000 hours of generation. Replacement of piston rings will take two men about 3 hours per engine.(14)

As such, annual ring replacement for the 693 engines becomes a full time task for two maintenance persons.

Unscheduled maintenance will primarily involve concentrator tracking mechanisms. An inventory of spare parts will be maintained.

Key safety considerations for the Case 7 System include the possibility of burns or eye damage from concentrators, and possible release of gaseous chlorine from battery modules. Burns and eye damage from concentrators should not be a problem if proper safety procedures are developed and followed. The danger is primarily at the focal point of the concentrator; however, safety procedures must also address the possibility of a psuedo line focus which can occur as solar radiation strikes the concentrator obliquely during slewing.

The major safety concern for the battery storage system is the release of gaseous chlorine in the event of a battery module case rupture.[2] The Mark 4 battery system design minimizes the possibility of such ruptures by keeping operating temperatures and pressures near ambient, by the use of nonflammable coolants, by keeping hydrogen concentrations at a low level, and by use of automatic safety interlocks. Should a rupture occur despite these precautions, the normal storage of chlorine in a solid hydrate form further suppresses the release of gaseous chlorine.

10.7.2 System Construction Considerations

A schedule for the design, procurement, and construction of the Case 7 System is shown on Figure 10.7-4. Total elapsed time from initiation of preliminary specifications to initial plant operation is 24 months.

Key assumptions used in preparing the schedule are as follows.

- A peak work force of about 150 men is anticipated, with a wide range of skill levels.
- An 8-hour day/20-day work month is assumed.
- Seven 4-man crews assemble 21 dish/turbine/generator units per week.[8]
- Foundations for dishes are drilled and poured at 5 per day.
- Electrical cabling connecting collectors is buried during early stages of construction. Electrical connections are made as dishes are erected.

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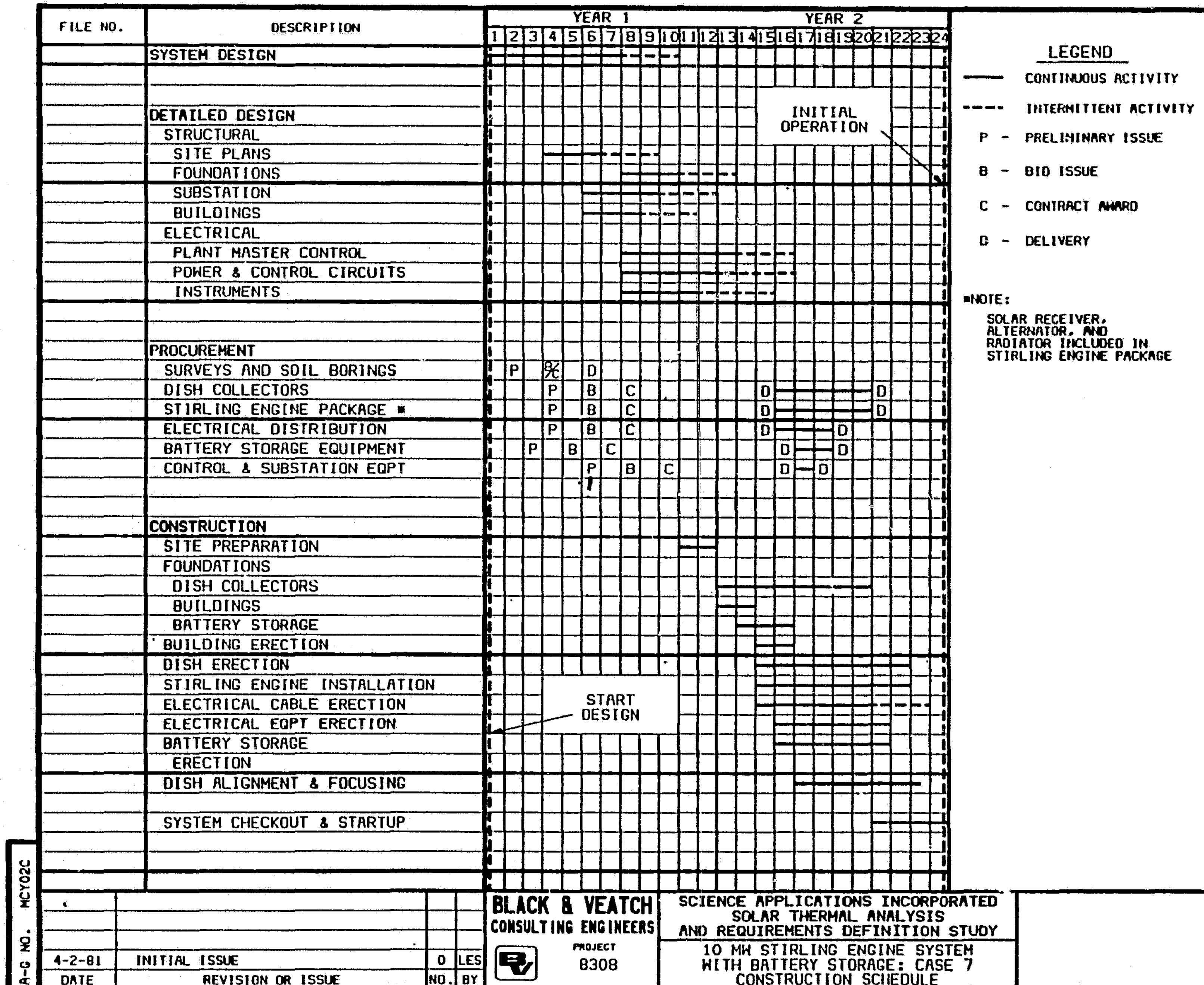

FIGURE 10.7-4 CASE 7 CONSTRUCTION SCHEDULE

10.7.3 System Cost Estimates

A determination of Case 7 capital and O&M costs has been made; a summary of those costs, broken down by subsystems, is presented on Table 10.7-4. It can be seen that the collector subsystem constitutes a large share of the overall system cost (about 50 per cent); the energy storage subsystem contributes the next highest cost share (about 15 per cent). Key assumptions in the cost determination were as follows.

- Collector, receiver, and power conversion unit material costs ($100/m^2, $40/kWe and $90/kWe) are in agreement with the Task 1 data base(16) and with DOE cost goals.(17)
- Electrical energy transport subsystem costs were based on a material take-off generated for Case 7.
- Energy storage costs were based on an installed cost estimate of 60 $/kWh for batteries and 175 $/kW for power conditioning and installation.(4)

Total capital costs include 15 per cent contingencies and 32 per cent indirects; indirects include engineering and construction management fees, administration and start-up costs, and AFDC.

10.7.4 System Sensitivity Analyses

Sensitivity analyses for the Case 7 System have been performed in order to provide a basis for identifying major cost/performance/design drivers and to determine their impacts; these sensitivity analyses are similar to those done for Case 1. System sensitivities to the following five variables have been analyzed.

- Subsystem Cost.
- Subsystem Efficiency.
- Subsystem Size.
- Site Variables.
- Installation Variables.

10.7.4.1 Subsystem Cost. The impact on total system cost of increasing subsystem cost by 20 per cent, one at a time, has been determined. The results of that analysis are summarized on Table 10.7-5. Key cost drivers are collector subsystems and electric energy storage.

TABLE 10.7-4. CASE 7 COST SUMMARY

Item		Capital Cost*
Land		233
Site Preparation		140
Collector Field		12,457
Concentrators	7,831	
Receivers	693	
Concentrator/Receiver Installation	2,803	
Foundations (Installed)	1,130	
Electric Power Generation		3,247
Stirling Engine	1,559	
Alternator	693	
Heat Rejection	104	
Installation	891	
Electric Energy Transport		2,028
Power Distribution Equipment	774	
Installation	1,254	
Electric Energy Storage		3,639
Batteries	1,845	
Power Conditioning	871	
Installation	923	
Master Control		1,750
Balance of Plant		358
Subtotal		23,852
Contingencies (15 per cent)		3,578
Total Direct Costs		27,430
Indirects (32 per cent)		8,778
Total		36,208

Operations and Maintenance Cost: $382,000/year

*Capital costs in 1,000's of 1980 dollars.

TABLE 10.7-5. SENSITIVITY OF SYSTEM COST TO 20 PER CENT INCREASE IN SUBSYSTEM COST

Subsystem	Base Cost* $	Adjusted Cost* $	Adjusted System Cost** $	Per Cent Change
Collector	12,457	14,948	39,989	10.4
Electric Power Generation	3,247	3,896	37,193	2.7
Electrical Energy Transport	2,028	2,434	36,825	1.7
Electrical Energy Storage	3,639	4,367	37,313	3.1
Master Control	1,750	2,100	36,739	1.5
Other	731	877	36,430	0.6

*In 1,000's of 1980 dollars.

**Total system cost including 20 per cent increase in a single subsystem cost, and including contingencies and indirects. Base total system capital cost is 36,208,000.

10.7.4.2 Subsystem Efficiency. The sensitivity of system cost to increases in subsystem efficiency are shown on Table 10.7-6. The analysis assumed that other subsystems would be scaled so as to maintain the original system output. The greatest overall impact is through increasing the power conversion efficiency; doing so allows decreasing the number of collectors, and the size of the electrical energy network.

10.7.4.3 Subsystem Size. The impact of increasing/decreasing the various subsystems by 50 per cent has been evaluated. Several scenarios have been developed for adjusting the remainder of the system when one subsystem size is increased/decreased in size. Results are summarized on Table 10.7-7. The analysis was based on the following assumptions.

- Economy of scale for capital costs was not considered (e.g., a 50 per cent increase in total system size was assumed to increase system cost by 50 per cent).
- Land, site preparation, electrical, control, and balance of plant costs were assumed to vary directly with collector area. While this assumption is not rigorous, the error involved is considered to be small.

10.7.4.4 Site Variables. System sensitivity to changes in site variables has been analyzed. In general, evaluations of such sensitivities are dependent on specific site parameters. As such, their quanitative evaluation is beyond the scope of this study. Also, in some cases (such as sensitivity to wind loading) cost sensitivity data is not available from equipment manufacturers. In other cases (such as sensitivity to topopgrahy) significantly different designs may be required. This analysis presents semi-quanitative and qualitative system sensitivity to major site variables in tabular form, Table 10.7-8.

10.7.4.5 Installation Variables. The sensitivity of overall system costs to 20 per cent reductions in respective system component installation costs are given on Table 10.7-9. Overall system costs are shown to be most sensitive to collector installation costs.

TABLE 10.7-6. SYSTEM SENSITIVITY TO INCREASES IN SUBSYSTEM EFFICIENCY*

Subsystem Altered (Efficiency Change)	Collector Subsystem	Storage Subsystem	Power Convs Subsystem	Energy Transport Subsystem	Decrease in System Capital Cost
Collector (0.64 to 0.70)	Nominally 10 per cent fewer collectors required.	None	Engine/alternator power capacity must be increased by 10 per cent. Ten per cent lower engines required.	Nominally 10 per cent less power cable required; cable size to individual collectors may increase.	Nominal 6.4 per cent.
Storage (0.65 to 0.72)	Nominally 3 per cent fewer collectors required.	--	Nominally 3 per cent engines required.	Nominally 3 per cent less power cables.	Nominal 2.3 per cent.
Power Conversion (0.40 to 0.44)	Nominally 10 per cent fewer collectors required.	None	Nominally 10 per cent fewer engines required.	Nominally 10 per cent fewer.	Nominal 7.7 per cent.
Electrical Energy Transport (0.97 to 0.98)	Nominally 1 per cent fewer collectors required.	--	Nominally 1 per cent fewer engines	Nominally 1 per cent less cable required.	Nominal 0.8 per cent.

*This analysis assumes that the system design is adjusted so as to maintain the designed output power. It also assums that efficiency increases are achieved at no change of cost for the subsystem in question.

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TABLE 10.7-7. SYSTEM SENSITIVITY TO COMPONENT SIZE CHANGES

Sensitivity Scenario	Scenario Options Label	Description	Impact on Overall System	Impact on System Capital Cost
50 per cent increase in storage size	A1	Increase number of collectors and engines by 18 per cent Increase energy transport size by 18 per cent	Daily energy production increased by 1.5 hours at rated power	Increases by 23 per cent
	A2	Scale up all subsystems by 50 per cent	Plant power input increases by 50 per cent Plant daily energy output increases by 50 per cent	Increases by 50 per cent
	A3	Do not change other subsystems	Increased storage allows changes in operating strategy Less energy lost to defocus in summer	Increases by 8 per cent
50 per cent decrease in storage size	B1	Decrease number of collectors and engines by 18 per cent Decrease energy transport size by 18 per cent	Daily energy production decreased by 1.5 hours at rated conditions	Decreases by 23 per cent
	B2	Scale down all subsystems by 50 per cent	Plant power decreases by 50 per cent Plant daily energy output decreased by 50 per cent	Decreases by 50 per cent
	B3	No changes in other subsystems	Some collectors will have to be defocused when storage becomes full	Decreases by 8 per cent
50 per cent increase of modular dish size/engine size	C1	Number of dishes kept constant Increase energy transport size by 50 per cent Increase storage capacity by 50 per cent	See A2	See A2
	C2	Number of dishes reduced to maintain level of power collected Maintain size of storage	None	Uncertain impact
50 per cent decrease of modular dish size/engine size	D1	Number of dishes kept constant Decrease energy transport size by 50 per cent Decrease storage capacity by 50 per cent	See B2	See B2

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TABLE 10.7-7 (Continued). SYSTEM SENSITIVITY TO COMPONENT SIZE CHANGES

Sensitivity Scenario	Scenario Options		Impact on Overall System	Impact on System Capital Cost
	Label	Description		
	D2	Number of dishes increased to maintain level of power collected Maintain size of storage	None	Uncertain impact
50 per cent increase of total system size	E1	Increase number of collection modules by 50 per cent No change in individual modules	See A2	See A2
	E2	Increase size of individual collection modules by 50 per cent Increase number of collectors by 50 per cent Increase energy transport by 50 per cent Increase storage capacity by 50 per cent Increase number of engines by 50 per cent	See A2	See A2
50 per cent decrease of total system size	F1	Decrease number of collection modules by 50 per cent No change to subsystems in individual modules	See B2	See B2
	F2	Decrease size of individual collection modules by 50 per cent Decrease number of collectors by 50 per cent Decrease energy transport by 50 per cent Decrease storage capacity by 50 per cent Decrease turbine size by 50 per cent	See B2	See B2

TABLE 10.7-8. CASE 7 SENSITIVITY TO SITE VARIABLES

Variable	Baseline Design Basis	System Sensitivity
Insolation (vary by 10 per cent)	• Design point insolation at 950 watts/m^2. • Field sized to fill 3 hours storage on March 21 (clear day assumed).	• 10 per cent decrease of clear day insolation requires 12 per cent increase in collector field size, with accompanying increase in electrical distribution network. Engine/alternator capacity decreased by 10 per cent. • System capital cost increases by 8 per cent.
Wind Loading	• Concentrator and foundation design requirements. -- Operate in winds to 50 km/h (31 mph). -- Slew to stow in winds to 80 km/h (50 mph). -- Survive in stowed position in winds to 120 km/h (75 mph).	• Data on concentrator cost vs. design wind load not available.
Seismic Zone Criteria	• Concentrator design based on 0.35 g lateral acceleration. • Seismic Zone 3.	• Design is controlled by wind loading rather than seismic considerations; therefore, system design not greatly sensitive to seismic conditions. • Seismic Zone 4 may require higher than 0.35 g lateral acceleration criterion.
Soil Conditions	• Competent bearing strata near the surface assumed.	• Concentrator foundation cost is estimated to be 4.7 per cent of total system cost; therefore, only slight cost sensitivity is expected.
Topography	• Relatively flat, level land area with few trees. • Minimal site preparation. • Concentrator and piping layout based on flat, level land.	• Impacts of rugged terrain include the following. -- Large increase in site preparation costs. -- Reduced field performance due to increased mutual shadowing of concentrators or significantly increased piping runs and cost. • Land rising to the north permits higher ground cover ratio and more compact system.

TABLE 10.7-9. CASE 7 SENSITIVITY TO INSTALLATION COSTS

Item	Installation Cost* (per cent total) $	Per Cent Decrease in Total System Cost with 20 Per Cent Decrease in Installation Cost
Concentrators/Receivers	2,803,000 (11.8)	2.35
Concentrator Foundations	1,130,000 (4.7)	0.95
Electrical Power Generation	891,000 (3.7)	0.75
Electrical Energy Transport	1,254,000 (5.3)	1.05
Electrical Energy Storage	923,000 (3.9)	0.77

*Prior to inclusion of contingencies and indirects.

10.7.5 Case 7 References

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10.8 CASE 8: DISTRIBUTED GENERATION WITH A STIRLING ENGINE AND NO ENERGY STORAGE

The Case 8 system is defined to be a 10 MWe parabolic dish system with dispersed generation via a Stirling engine. Distinguishing features of the case definition are as follows.

- Concentrators are patterned after the Acurex Low Cost Concentrator (all prior cases have used the General Electric concentrator).
- Generation is by means of Stirling engines mounted on each collector.
- No energy storage is utilized.
- A sensitivity study looks at the impact of increasing individual concentrator areas by 25 per cent.
- The system is located at Fort Worth, Texas, and is connected to a municipal utility grid.
- The design time frame is 1990.

The Case 8 system is designed to provide a net 10 MWe at noon on a clear March 25, with a design time point insolation of 950 watts/m^2 (301 Btu/h/ft^2).

10.8 SYSTEM DESCRIPTION

The Case 8 design has key characteristics similar to those for Case 7. The rationale for those design decisions were previously presented on Table 10.7-1. The key characteristics are as follows.

- The Stirling engine, patterned on the United Stirling 4-95 engine, uses helium as a working fluid, with the outer tube wall temperature at 810 C (1,490 F)(1).
- The solar receiver is similar to the non-heat pipe receiver being developed by Fairchild Stratos Division(2) except that no hybrid capabilities exist. The receiver aperture diameter has been reduced from the Case 7 design due to better concentrating capabilities of the Acurex concentrator(3). This results in lower radiative and convective losses for the Case 8 receiver than for the Case 7 receiver.
- Heat rejection is by means of a radiator mounted on the ground near each dish(4).

10.8.1.1 System Design Requirements. This subsection will present specific design requirements for the Case 8 system. Topics addressed will include the following.

- Site conditions,
- Site arrangement,
- System design point requirements,
- System functional requirements, and
- Standards and regulations.

Site Conditions. The Case 8 system is located at a site near Fort Worth, Texas. It is assumed for this study that the site selection can be made to minimize site preparation, and that plant support factors (roads etc.) are nearby. Table 10.1-2, given previously, lists the assumed site conditions for Fort Worth.

Site Arrangement. The physical layout for the Case 8 system is illustrated on Figure 10.8-1. The collector field, which covers about 20 hectares (50 acres), contains 423 collectors. The field is divided into nine electrical power collection modules. The three-phase, 480 volt ac power generated by each collector unit is transmitted to the center of the collection module, where it is stepped up to 4,160 volts for transmission to the plant switch yard at the perimeter of the field. Control, administration, and maintenance capabilities are located at the field perimeter.

System Design Point Requirements. The baseline system for Case 8 was designed to provide rated power (10 MWe net) at noon March 21. A design point insolation of 950 watts/m^2 (301 Btu/h/ft^2) was assumed. A functional flow diagram for the system is shown on Figure 10.8-2. Design details for the individual subsystems are listed on Table 10.8-1.

System Functional Requirements. In accordance with the Case 8 system definition, the Case 8 system has neither storage or hybrid fossil capabilities. As such the system operates in a strictly "sunfollowing" mode, i.e. plant electrical outputs closely follow changes in available solar power. This sunfollowing operation can be placed into three categories.

- Start-up/shutdown state,
- Quasi steady state, and
- Transients.

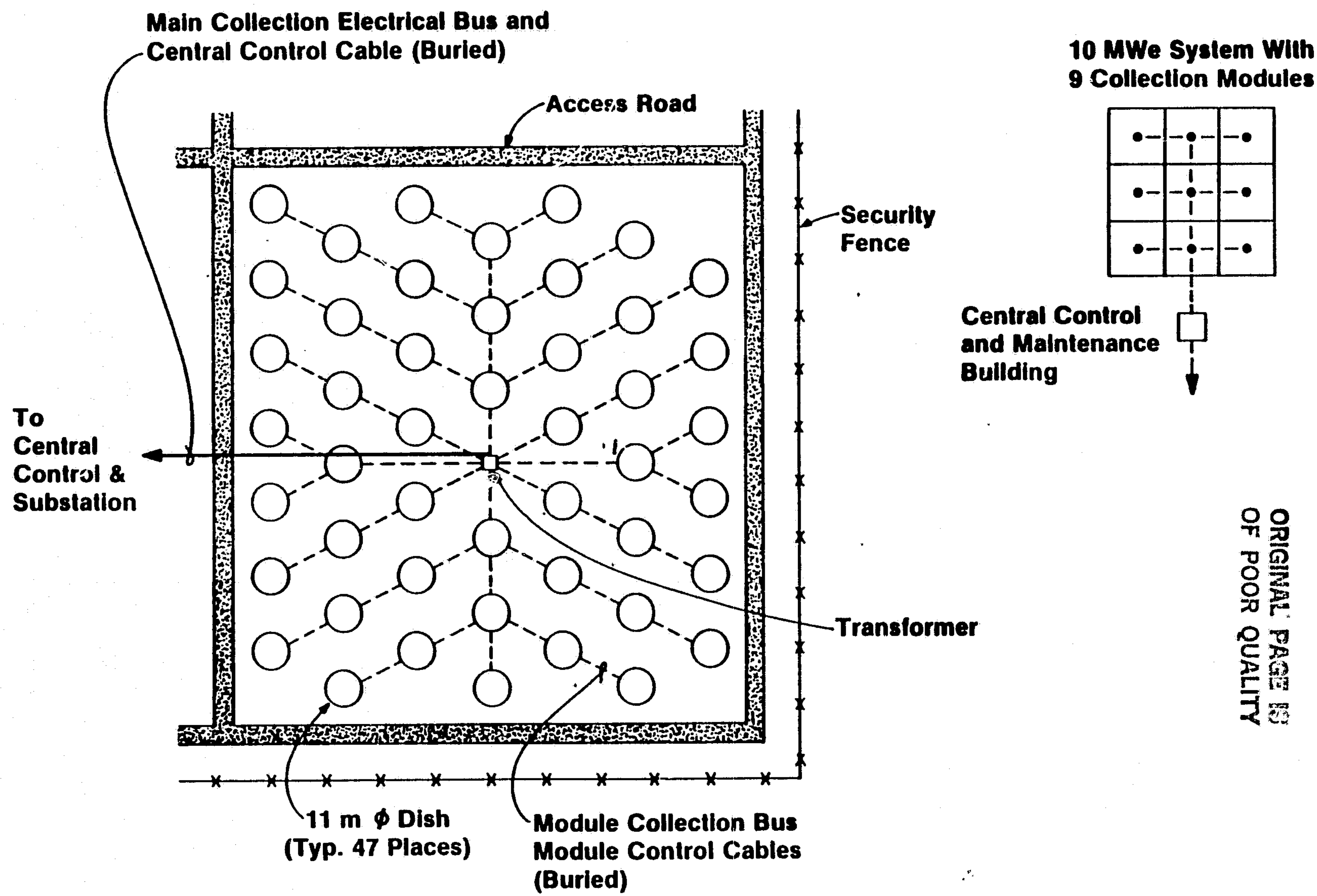

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FIGURE 10.8-1 CASE 8 STIRLING CYCLE COLLECTION MODULE PLAN ARRANGEMENT

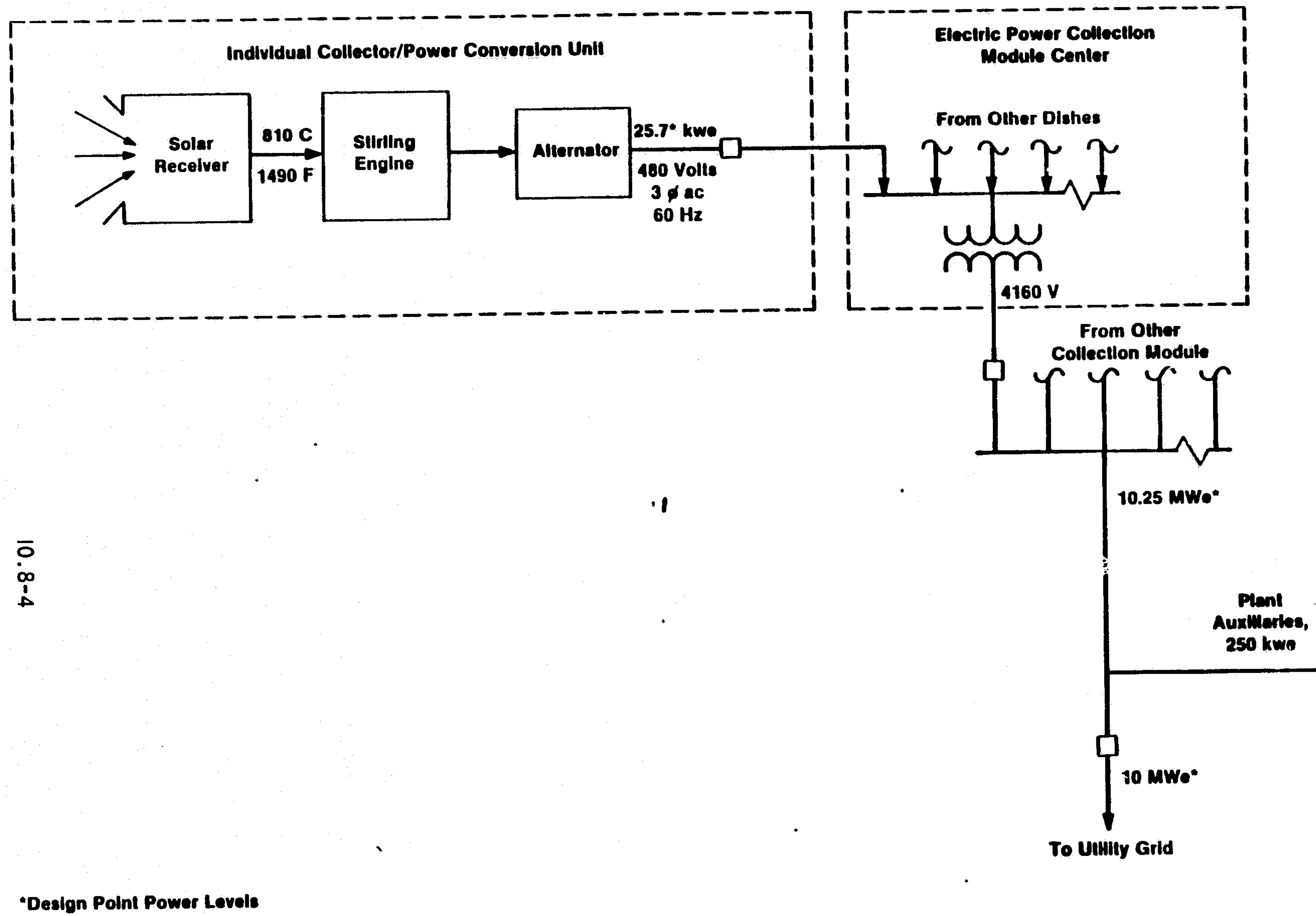

FIGURE 10.8-2 CASE 8 FUNCTIONAL FLOW DIAGRAM

ABLE 10.8-1. CASE 8 SUBSYSTEM DESIGN SUMMARIES

COLLECTOR SUBSYSTEM

Parameter	D. P. Value*
Concentrator(3)	
Dish Diameter, m (ft)	11 (36)
Effective Aperture Area, m^2 (ft^2)	95 (1020)
Gap Loss Factor	0.919
Reflectivity	0.95
Blocking Factor	0.989
Shading Factor	0.998
Intercept Factor	0.95
Concentrator Effectiveness	0.819
Stirling Receiver(2)	
Outer Diameter, m (ft)	0.76 (2.5 ft)
Aperture Diameter, m (ft)	0.17 (.56)
Working Fluid Temperature C (F)	810 (1490)
Power Input, kWt (MBtu/h)	73.9 (0.253)
Power Output, kWt (MBtu/h)	68.4 (0.233)
Efficiency	0.926

*Design point value.

ELECTRIC POWER GENERATION SUBSYSTEM(1, 4)

Parameter	D. P. Value*
Cycle	Stirling
Engine Type	Double acting, four cylinder
Working Fluid	Helium
Outer Tube Temperature, C(F)	810 (1,490)
Helium Mean Pressure, MPa (psia)	15 (2,200)
Thermal Input, kWt (MBtu/h)	68.4
Cycle Efficiency	0.40
Shaft Output Power, kWm (hp)	27.4
Shaft Speed, rpm	1800
Alternator Efficiency	0.94
Electric Accessory Load, kWe	0.7
Collector Module Electric Power, kWe	25.7

*Design point value.

MASTER CONTROL SUBSYSTEM

- Central Control Mini-computer.
- Main Control Panel.
- Programmers Console.
- CRT Displays.
- Printer.
- Interface Hardware.
  - --Engine Controllers.
  - --Collector Controllers.
  - --Energy Transport Controllers.
  - --System Instrumentation.

ELECTRICAL ENERGY TRANSPORT SUBSYSTEM

- General electrical layout as per Figure 10.8-1.
  - -- Generation at 480 volt, three-phase ac.
  - -- Nine collection modules.
  - -- Step up to 4160 volt at each collection center.
- Direct buried cable with EPR insulation and CSP Jacket.
- Switchgear and lighting protection.

BALANCE OF PLANT

- Buildings.
  - -- Central Control and Maintenance.
  - -- Warehouse (spare parts inventory).
- Maintenance Equipment.
  - -- Truck.
  - -- Crane.
  - -- Washing Vehicle.
  - -- Tools.
- Fire Protection System.
- Plant Lighting System.
- Roads.
- Security Fence.

Start-up of the system consists of several steps. First, each collector is commanded to begin tracking the sun. As the receiver temperature approaches the engine start-up threshold, an electrical starting motor begins cranking the engine. As the thermal heat input to the engine increases, the speed increases until the synchronization speed is reached (each engine has a microprocessor which monitors and controls engine speed). At this point, the engine/alternator is brought into synchronization, and the switch to the system electrical network is closed. Shutdown essentially reverses this process. As thermal heat input to the engine decreases (due either to lack of insolation or to defocusing of the dish), a threshold is reached where the engine can no longer maintain synchronization speed. At this time the switch to the electrical network is opened and the engine is shutdown.

The quasi steady state operation on the system is relatively straight forward. For small rates of change in engine heat input, there is no difficulty in maintaining the constant synchronization speed of 1800 rpm. The engine microprocessor adjusts the helium inventory (and thereby the pressure) so as to maintain the proper torque/speed correlation[5].

For more severe transients in the solar power, maintaining of engine synchronization may become difficult. It may become necessary to have repeated start-up/shutdown sequences during intermittent cloud cover. Should such sequences become too frequent, shutdown for the day may be advisable to prevent excess cycling of the receiver and engine. (While not incorporated in the Case 8 design, a small buffer storage within the receiver is very likely cost effective in reducing the cycling of engines, as well as in reducing the number of days where operation is suspended due to intermittent clouds.)

In achieving the above system operating modes, the Collector Subsystem must fulfill the following requirements.

- Two axis tracking of the sun.
- Deliver up to 68.4 kWt (0.233 MBtu/h) to the Stirling engine.
- Operate in winds up to 52 km/h (30 mph).
- Slew to stow in winds up to 80 km/h (50 mph).

- Survive stowed in winds up to 120 km/h (75 mph).
- Survive 1/4 g lateral seismic load.

The Power Conversion Unit including the Stirling engine alternator, and heat rejection radiator must fulfill the following functional requirements.

- Generate up to 25.7 kWe per dish unit.
- Remain synchronized with the grid.

The Energy Transport system must fulfill the following functional requirements.

- Collect up to 1.2 MWe at 480 volts ac at each collection center.
- Step-up power to 4,160 volts ac for transmission to the overall system output bus.
- Have line losses not exceeding 0.3 MWe (3 per cent of total peak power generation).
- Provide switching for isolation of collector modules and individual collectors.
- Provide lightning protection.

The Master Control System must fulfill the following functional requirements.

- Send command signals to individual collectors to track, defocus, or stow.
- Coordinate solar system start-up.
  - -- Commence collector tracking of the sun when turbine start-up has been initiated.
  - -- Initiate engine start-up.
  - -- Govern synchronization of the engine/alternator with the grid.
- Coordinate solar system shutdown.
  - -- Through the engine microprocessor, sense engine inability to maintain synchronization.
  - -- Disconnect engine/alternator from the grid.
  - -- Cease tracking of sun.
- Provide warnings and alarms for faulty operation.

Standards and Regulations. The Case 8 system design is responsive to a number of laws, ordinances, codes, and standards. A listing of applicable codes was given previously in Section 10.1.1.1.

10.8.1.2 Operational Characteristics. Four areas of operational characteristics for the Case 8 System have been identified. These topics are as follows.

- Personnel,
- Consumables,
- Maintenance, and
- Safety.

An operating and maintenance staff of six people is anticipated. This staff would include three plant operators with duty hours arranged so as to cover the average system operation 12 hours per day, 7 days per week. Each day two operators shifts would coincide during a part of that day. During those times, as well as on cloudy days, operators would perform inspections and routine maintenance. The remaining workers would perform maintenance duties full time.

Consumables for the system will be primarily concentrator washing solution. Washing solution consumption is estimated to be about 42,000 liters (11,000 gallons) per month; the solution makeup is primarily water. Other system consumables are low quantity.

One of the primary maintenance activities will be washing of concentrators. Using a special washing vehicle, the monthly washing process is anticipated to take about 15 minutes per concentrator, adding up to about 13 man-days per month. Other routine maintenance activities will include annual inspections of electrical equipment (switchgear, tranformer oil level, etc), concentrator reflective surfaces, etc.

Scheduled Stirling engine maintenance includes annual replacement of piston rings(6) and engine overhaul after 30,000 operating hours(6). Replacement of piston rings will take two men about three hours per engine(6); for 423 engines this amounts to about 1-1/3 man-years.

Unscheduled maintenance will primarily involve concentrator tracking mechanisms. An inventory of spare parts will be maintained.

The main safety considerations for the Case 8 System is the possibility of burns or eye damage from concentrators. This, in general, should not be a problem since the danger is primarily at the focal point of the concentrator; an additional concern is a possible pseudo-line focus resulting from

solar radiation striking concentrators obliquely during slewing. Safety procedures must be developed which assure that personnel will not be in a danger zone while concentrators are tracking or slewing.

10.8.2 System Construction Considerations

The schedule for the design, procurement, and construction of the Case 8 System is quite similar to that of the Case 7 system as given on Figure 10.7-4. Total elapsed time from initiation of preliminary specifications to initial plant operation is 24 months.

Key assumptions used in preparing the schedule are as follows.

- A peak work force of about 100 men is anticipated, with a wide range of skill levels.
- An 8-hour day/20-day work month is assumed.
- Four 4-man crews assemble 12 collector/engine/alternator units per week.
- Foundations for dishes are drilled and poured at three per day.
- Electrical cabling connecting collectors are buried during early stages of construction. Electrical connections are made as dishes are erected.

10.8.3 System Cost Estimates

A determination of Case 8 capital and O&M costs has been made; a summary of those costs, broken down by subsystems, is presented on Table 10.8-2. It can be seen that the collector subsystem constitutes a large share of the overall system cost (over 50 per cent). System cost is considerably less than for the Case 2 10 MWe plant. This is a result of using the Stirling engine with improved cost performance over the open cycle Brayton turbine, as well as increased cost effectiveness in using the Acurex concentrator. Key assumptions in the cost determination were as follows.

- Concentrator costs of $\$125/m^2$ installed, based on manufacturer's estimates[3].
- Uninstalled receiver costs of $40/kWe, based on DOE cost goals[7].
- Engine costs of $90/kWe, alternator costs of $40/kWe, and heat rejection at $150/engine (all costs uninstalled)[4].

TABLE 10.8-2. CASE 8 COST SUMMARY

Item	Capital Cost* $1,000	
Land		125
Site Preparation		75
Collector Field		6,652
Concentrators (Installed)	5,076	
Receivers (Installed)	703	
Foundations (Installed)	873	
Electric Power Generation		1,982
Stirling Engine	952	
Alternator	423	
Heat Rejection	63	
Installation	544	
Electric Energy Transport		1,003
Power Distribution Equipment	487	
Installation	516	
Master Control		1,500
Balance of Plant		302
Subtotal		11,639
Contingencies (15 per cent)		1,746
Total Direct Costs		13,385
Indirects (29 per cent)		3,882
Total		17,267

Operations and Maintenance Cost: $260,000/year.

Total costs include 15 per cent contingencies and 29 per cent indirect costs; indirect costs include engineering and construction management fees, administration and start-up costs, as well as AFDC.

10.8.4 Sensitivity Study

The Case 8 sensitivity study examines the impact on system cost of increasing individual concentrators area by 25 per cent. Total reflective area has been kept constant by reducing the number of concentrators by 25 per cent. Table 10.8-3 gives the resultant changes in cost for each subsystem.

Costs for land, site preparation, and balance of plant do not change since reflective area, and thereby land area, does not change. Concentrator costs increase on a per unit area basis. Studies by both Acurex and Ford Aerospace show 11 meters as the size for minimum concentrator cost(8, 9). Electric power conversion costs decrease on a per kW basis(9). The electrical energy transport system costs decrease somewhat; cable sizes increase due to increased power/current flow per cable, but cable lengths and number of terminations decrease due to fewer power generation sites. The Master Control System cost decreases due to a fewer number of units to monitor and control.

10.8.5 Case 8 References

(1) Worth Percival and Hans-Goran Nelving, "First Phase Testing of Solar Thermal Engine at United Stirling," presented at the Parabolic Dish Solar Thermal Power Annual Program Review, Pasedena, California, January 13-15, 1981.

(2) R. A. Haglund, "Non-Heat Pipe Receiver/P40 Stirling Engine," presented at the Parabolic Dish Solar Thermal Power Annual Program Review, Pasedena, California, January 13-15, 1981.

(3) Private communication to M. D. Querry, Black & Veatch, from Roger Bedard, Acurex, February 23, 1981.

(4) Private communication to L. E. Stoddard, Black & Veatch, from Worth Percival, United Stirling, Incorporated, February 19, 1981.

(5) Private communication to L. E. Stoddard, Black & Veatch, from Worth Percival, United Stirling, Incorporated, March 6, 1981.

(6) Private communication to L. E. Stoddard, Black & Veatch, from Worth Percival, United Stirling, Incorporated, March 15, 1981.

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TABLE 10.8-3. SYS
CHAN

Item			
Land			
Site Preparation			
Collector Field			
Electric Power Generation			
Electrical Energy Transp			
Master Control			
Balance of Plant			
Subtotal			
Contingencies and Indirects			
Total			

Costs are given in

(7) Private communication to L. E. Stoddard, Black & Veatch, from John Lucas, Jet Propulsion Laboratories, August 4, 1980.

(8) Private communication to L. E. Stoddard, Black & Veatch, from Roger Bedard, Acurex, March 20, 1981.

(9) Ford Aerospace and Communications Corporation, Phase I of the First (Solar) Small Power System Experiment, Final Report, May 5, 1979.

10.9 CASE 9: 10 MWe DISTRIBUTED GENERATION VIA CLOSED CYCLE BRAYTON TURBINES

The Case 9 system definition is a 10 MWe parabolic dish system using a distributed generation via closed Brayton cycle (CBC) turbines mounted at the dish focal point; no storage or hybrid capabilities are included. The concentrator specified for Case 9 is either the GE or Acurex low cost concentrator, with performance analysis from prior cases being the basis of selection. The system is located at an isolated government installation or military base near Phoenix, Arizona. A diesel generator provides onsite backup capabilities.

In the Case 9 system design, the system is sized to produce 10 MWe (using solar power only) with a 950 watts/m^2 (301 Btu/h/ft^2) insolation and an ambient temperature of 24 C (75 F), which is appropriate for noon March 21 in Phoenix. Because the system has neither storage nor hybrid fossil capabilities, the system output is "sunfollowing" in nature. It is assumed that nighttime and cloudy day electricity generation will be provided by a diesel generator, as in Case 2.

A 1990 time frame is designated for the Case 9 design. This time frame allows the assumption of development of new materials and equipment, and sufficiently large production rates to reduce to a mature level capital costs of currently non-commercial items.

10.9.1 System Description

The baseline system design for Case 9 has the following key characteristics; rationale for these design decisions are listed in Table 10.9-1.

- The turbine and receiver are closed cycle versions patterned after those currently being developed by Garrett AiResearch Corporation for open cycle Brayton applications, with air as the working fluid.[1, 2] The receiver differs from the Garrett receiver in that no hybrid fossil capabilities are included.
- A turbine inlet temperature (TIT) of 870 C (1,600 F) is utilized.
- A mass inventory (pressure) control technique, rather than TIT control as used with the Case 2 open Brayton cycle, is used.

TABLE 10.9-1. KEY DESIGN DECISIONS FOR CASE 9

Design Decision	Favoring Rationale	Opposing Rationale
Turbine inlet temperature (TIT) of 870 C (1,600 F).	Higher TIT gives higher cycle efficiency. Available Brayton engine is capable of 870 C (1,600 F) operation.[1] Receiver can be built to operate at 870 C (1,600 F) assuming projected development of nitrogen dispersion strengthened steels.[2, 3]	Current receiver design is limited to 820 C (1,500 F) operation because of material limitations.[2, 3]
Air rather than helium as the working fluid[4]	Air allows use of lower operating pressures to get same mass flow rate. Air presents less serious leakage problems. Available Brayton engine is designed for air usage.	Helium possesses better heat transfer characteristics, giving better regenerator effectiveness.
Rectification of ac generator output to dc for power collection. Subsequent inversion of power to ac.	Avoids problems of synchronizing all turbines. 60 Hz power operation necessary for synchronization requires gear boxes.[1] Current machinery development uses rectification/inversion method.[1]	Larger size cables required for transmitting low voltage (200 volt dc) than for higher voltage ac. Rectifier/inverter add to cost and have associated power losses.

- The field consists of 11-meter (36 feet) diameter concentrators patterned after the Acurex Low Cost Concentrator. The concentrators are arranged in a diamond pattern, with a 0.25 ground cover ratio, and occupy about 28 hectares (70 acres).
- Power generation by the CCB turbines is slightly variable frequency ac, which is rectified for collection. Inversion back to ac takes place at nine locations within the field, with step-up transformers at each of these locations.

Selection of the Acurex Concentrator rather than the GE Concentrator was based on a projected lower capital cost per unit of thermal power delivered by the receiver at the design time point.* For similar applications (heating air to 870 C (1,600 F)), the Acurex and GE collectors deliver design point powers of 70.4 kWt and 72.7 kWt, respectively. The estimated costs for the collectors (installed concentrators and receivers, with foundations) is $15,700 and $17,500, respectively; this yields costs per unit thermal power of $223/kWt and $241/kWt for the Acurex and GE collectors, respectively. In addition to the lower Acurex design time point cost, an additional consideration favoring the Acurex concentrator is the need to refurbish the GE concentrator panels every 10 years.

10.9.1.1 <u>System Design Requirements</u>. This subsection will present specific design requirements for the Case 9 baseline system. Topics addressed will include the following

- Site conditions,
- Site arrangement,
- System design point requirements,
- System functional requirements, and
- Standards and regulations.

<u>Site Conditions</u>. The Case 9 system is located at a site near Phoenix, Arizona. It is assumed for this study that the site selection can be made

*Selection of the Acurex Concentrator as the "best dish" for this study should not be interpreted as a general endorsement, since different applications, as well as changes in the cost/performance data used, could result in a different selection.

to minimize site preparation, and that plant support factors (roads etc.) are nearby. Table 10.2-2, given previously, lists the assumed Case 9 site conditions.

Site Arrangement. The physical layout for the Case 9 system is illustrated on Figure 10.9-1. The collector field, which covers about 28 hectares (70 acres), contains 603 collectors. The field is divided into nine electrical power collection modules, thereby reducing the length of the low voltage (200 v) direct current collection network with its attendant high cost/high power loss. These dc cables, as well as ac cables powering the concentrators, are direct buried along routes indicated on Figure 10.9-1. Inversion to ac and subsequent voltage step-up are accomplished at each of the nine central locations.

The central control facility as well as the maintenance shops are located in a building at the perimeter of the field; a warehouse for the spare parts inventory is located nearby. Also at the perimeter of the field are the four 2.5 MWe diesel generator units and the fuel storage tanks.

System Design Point Requirements. The baseline system for Case 9 is designed to provide rated power (10 MWe net) at noon March 21 using solar power only. A design point insolation of 950 watts/m^2 (301 Btu/h/ft^2) is assumed. A functional flow diagram of a single collector and power conversion unit, giving temperatures, pressures, flow rates, and power values is shown on Figure 10.9-2. Design details for the individual subsystems are listed on Table 10.9-2.

System Functional Requirements

In accordance with the Case 9 system definition, the Case 9 system has neither storage or hybrid fossil capabilities. Furthermore, the system load is defined to be a small government or military installation. As such, the system must operate in a modified "sunfollowing" mode. The lack of storage or hybrid means that the solar plant must follow changes in available solar power; a small load demand may require "defocusing" of some collectors to match solar output with the load. It is assumed that any inability to meet the load with the solar plant output will be met with the diesel generator units.

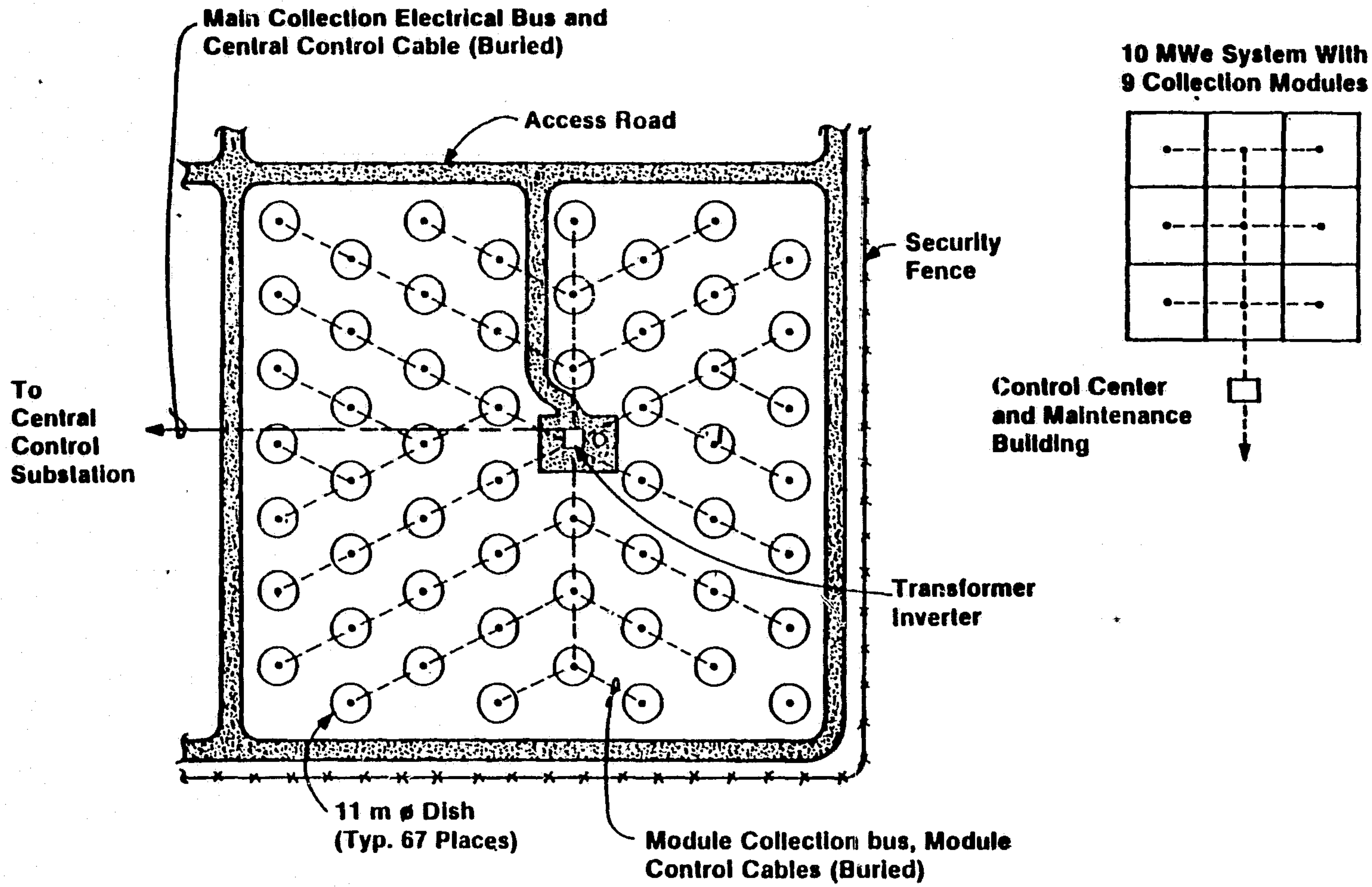

FIGURE 10.9-1 CLOSED BRAYTON CYCLE COLLECTION MODULE PLAN ARRANGEMENT

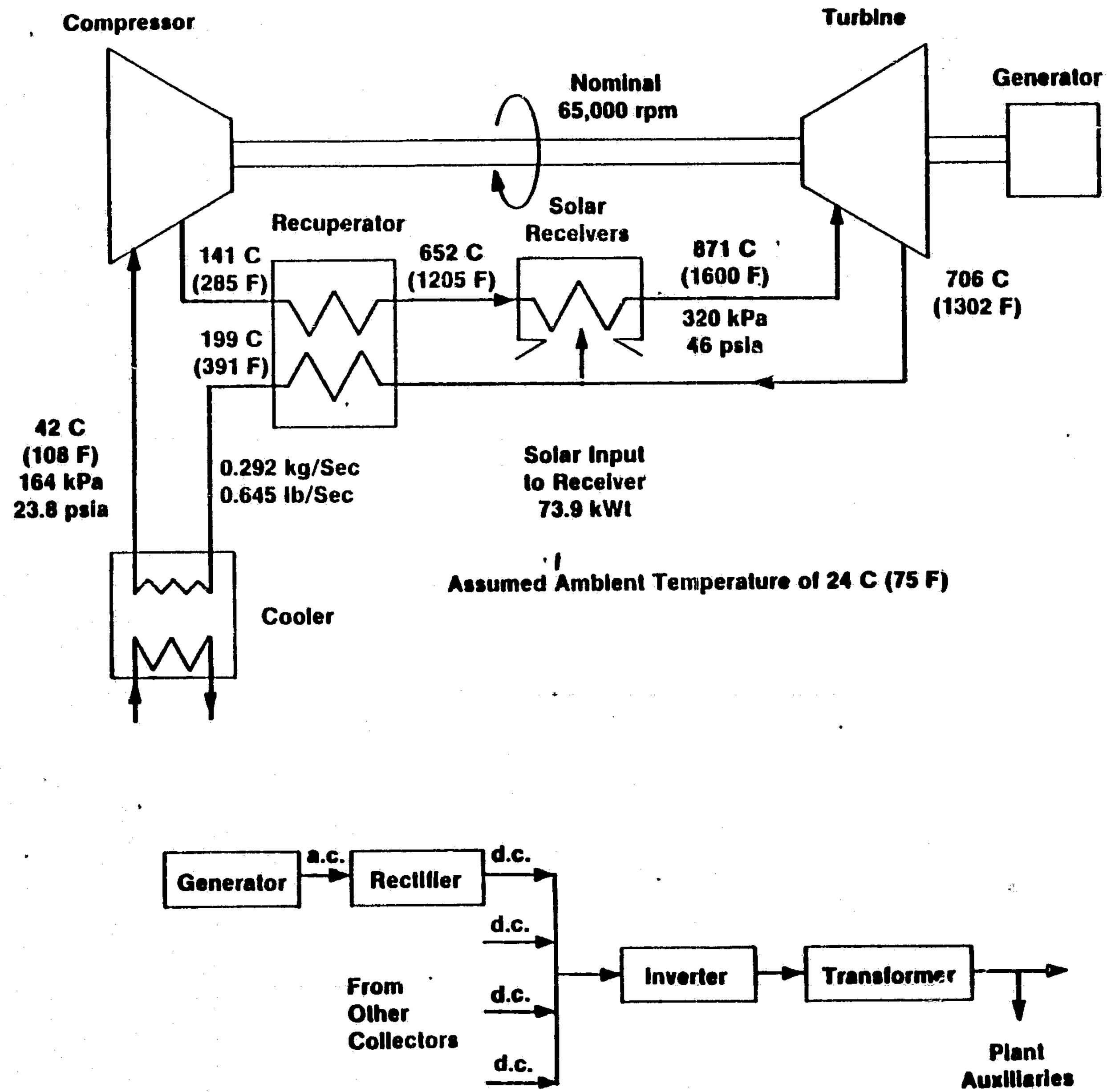

FIGURE 10.9-2 CASE 9 SYSTEM FUNCTIONAL FLOW DIAGRAM

TABLE 10.9-2. CASE 9 SUBSYSTEM DESIGN SUMMARIES

COLLECTOR SUBSYSTEM

Parameter	D. P. Value*
Concentrator[5]	
Dish Diameter, m (ft)	11 (36)
Effective Aperture Area, m^2 (ft^2)	95 (1,020)
Gap Loss Factor	0.919
Reflectivity	0.95
Blocking Factor	0.989
Shading Factor	0.998
Intercept Factor	0.95
Concentrator Effectiveness	0.819
Brayton Receiver[2, 3]	
Outer Diameter, m (ft)	0.76 (2.5)
Aperture Diameter, m (ft)	0.17 (0.56)
Inlet Temperature, C (F)	652 (1,205)
Outlet Temperature, C (F)	870 C (1,600)
Power Input, kWt (MBtu/h)	73.9 (0.252)
Power Output, kWt (MBtu/h)	70.4 (0.240)
Efficiency	0.95
Pressure Drop, kPa (psig)	14 (2.0)
Air Flow Rate, kg/sec (lbm/sec)	0.292 (0.645)

*Design point value.

Note: Receiver capability to operate at 870 C (1,600 F) dependent on commercial availability of nitrogen dispersion strengthened steel.[3]

ELECTRICAL POWER GENERATION SUBSYSTEM[1]

Parameter	D. P. Value*
Thermal Input, kWt (MBtu/h)	70.4 (0.240)
Cycle Efficiency	0.303
Shaft Power, kWm (hp)	21.3 (28.6)
Compressor Inlet Temperature, C (F)	42 (108)
Compressor Inlet Pressure, kPa (psia)	164 (23.8)
Turbine Inlet Temperature, C (F)	870 (1,600)
Shaft Speed, rpm	65,000
Compressor Compression Ratio	2.17
Turbine Expansion Ratio	1.98
Recuperator Effectiveness	0.90
Gearbox Efficiency	0.98
Shaft Accessory Load, kWm (hp)	0.08 (0.10)
Generator Efficiency	0.94
Rectifier Efficiency	0.96
Gross Electric Power, kWe (dc at rectifier)	18.8
Electric Accessory Load, kWe	0.91
Module Electric Power, kWe (dc)	17.8
Recuperator H.P. Inlet Temperature, C (F) (Compressor Outlet Temperature)	141 (285)
Recuperator H.P. Outlet Temperature, C (F) (Receiver Inlet Temperature)	652 (1,205)
Recuperator L.P. Inlet Temperature, C (F) (Turbine Exhaust Temperature)	706 (1,305)
Recuperator L.P. Outlet Temperature, C (F) (Exhaust Temperature)	199 (391)
Flow Rate, kg/sec (lb/sec)	0.292 (0.645)

*Design point value.

ELECTRICAL ENERGY TRANSPORT SUBSYSTEM

- General electrical layout as per Figure 10.9-1.
- Collection of 200 volt dc at 9 central locations.
- Buried cable with EPR or XLPE insulation (as appropriate) and CSP Jacket.
- Nine 1,500 kVA solid state static inverters.
  - -- 200 vdc to three phase 480 volt ac.
  - -- 0.94 efficiency at rated load.
  - -- Automatic synchronization with line signal.
- Nine 1,500 kVA, 4,160 volt/480 volt transformers with outdoor enclosure.
- Switchgear and lighting protection.

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MASTER CONTROL SUBSYSTEM

- Central Control Mini-computer.
- Main Control Panel.
- Programmers Console.
- CRT Displays.
- Printer.
- Interface Hardware.
  - -- Turbine Controllers.
  - -- Collector Controllers.
  - -- Energy Transport Controllers.
  - -- System Instrumentation.

DIESEL-GENERATOR BACKUP SYSTEM

- Four 2,500 kW fast-start diesel generators.
- 473,000 liter (125,000 gallon) fuel tank with oil containment berm.

BALANCE OF PLANT

- Buildings.
  - -- Central Control and Maintenance.
  - -- Warehouse (spare parts inventory).
- Maintenance Equipment.
  - -- Truck.
  - -- Crane.
  - -- Washing Vehicle.
  - -- Tools.
- Fire Protection System.
- Plant Lighting System.
- Roads.
- Security Fence.

C-4

The operating strategy for the solar plant calls for maximizing the percentage of the load demand met by the solar facility, thereby minimizing fuel consumption by the diesel generators. If the load demand is greater than the solar plant output, the solar facility operates in the pure "sun-following" mode. The diesel backup system, in addition to meeting the additional load requirement, must adjust to changes in load and to changes in solar plant output. If the load demand is less than the solar electrical output, the solar system must adjust to changes in load and to changes in solar input. This operating strategy is illustrated in Figure 10.9-3.

In achieving the above system operating modes, the Collector Subsystem must fulfill the following requirements.

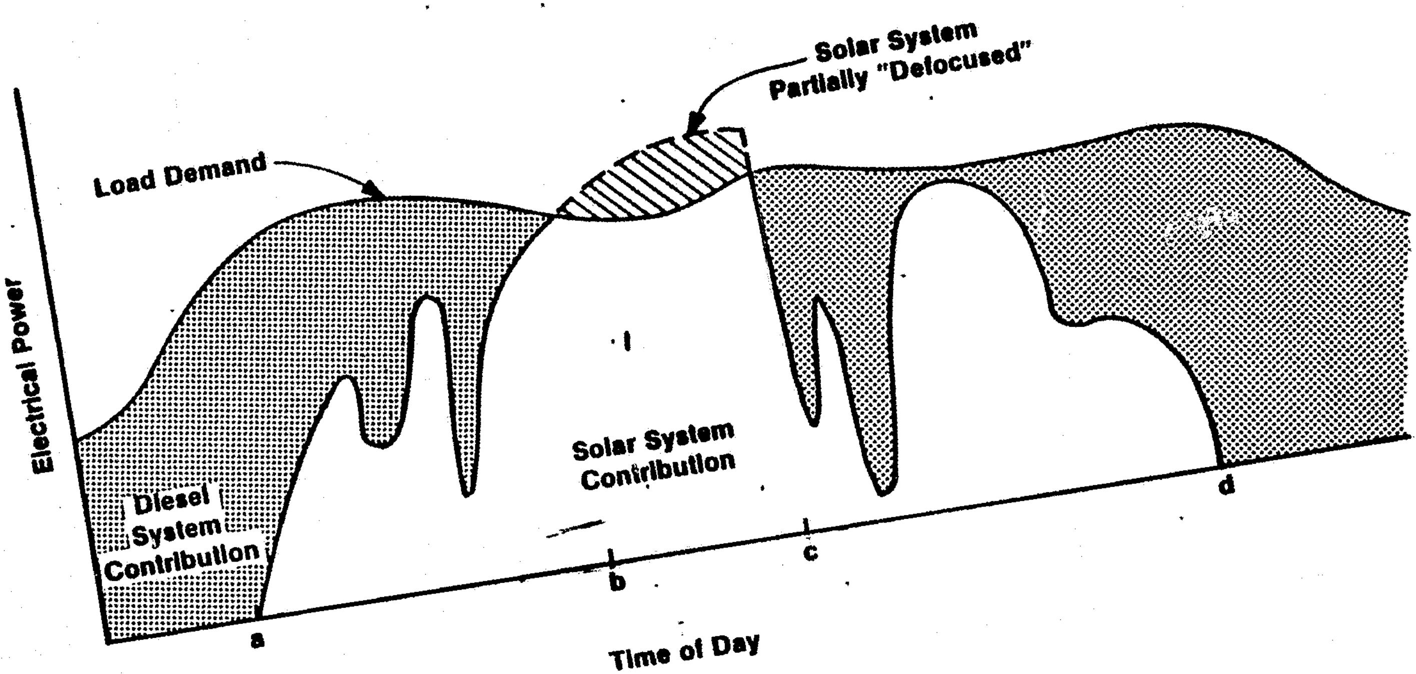
- Two axis tracking of the sun.
- Heat air from 652 C (1,200 F) to 870 C (1,600 F).
- Deliver up to 70.4 kWt (0.240 MBtu/h) to the turbine.
- Operate in winds up to 50 km/h (31 mph).
- Slew to stow in winds up to 80 km/h (50 mph).
- Survive stowed in winds up to 120 km/h (75 mph).
- Survive 1/4 g lateral seismic load.

The Power Conversion Unit, including the turbine, generator (with rectifier), recuperator, and compressor, must fulfill the following functional requirements.

- Generate up to 17.8 kWe dc per dish unit.
- Generate ac power; rectify to dc power.

The Electric Energy Transport System must fulfill the following functional requirements.

- Collect up to 1.2 MWe (200 volt dc) at each collection center.
- Invert dc to three-phase ac at 480 volts.
- Step up to 4,160 volts ac for transmission to the overall system output bus.
- Provide switching for isolation of collector modules and individual collectors.
- Provide lightning protection.



Times a to b, c to d: Sun following strategy, diesel system adjusts to load and solar changes

Time b to c: Solar load following strategy; collectors "defocused" to follow Load

FIGURE 10.9-3 CASE 9 OPERATING STRATEGY

The Master Control System must fulfill the following functional requirements.

- Send command signals to individual collectors to track, defocus, or stow.
- Coordinate solar system start-up.
  - -- Commence collector tracking of the sun.
  - -- Initiate turning of turbine/compressor via a starting motor.
  - -- Decrease diesel backup power as solar power increases.
- Coordinate solar system shutdown.
  - -- Cease tracking of sun.
  - -- Switch to diesel backup.
- Match power generation to load.
  - -- Maximize use of solar power.
  - -- Detect changes in load.
  - -- For increase of load, add collectors if some are defocused; if not, rely on diesel backup.
  - -- For decrease of load, reduce diesel backup if all collectors are tracking; if not, defocus additional collectors.
- Provide warnings and alarms for faulty operation.

Standards and Regulations. The Case 9 system design complies with applicable laws, ordinances, codes, and standards. Table 10.2-4 given previously lists applicable regulations, along with the more significant impacts of those regulations.

10.9.1.2 Operational Characteristics. Four areas of operational characteristics for the Case 9 System have been identified. These topics are as follow:.

- Personnel,
- Consumables,
- Maintenance, and
- Safety.

An operating and maintenance staff of six people is anticipated. This staff includes three plant operators with duty hours arranged so as to cover the average system operation 12 hours per day, 7 days per week. Each day, two of the operators' shifts would coincide during a part of that

day. During those times, as well as on cloudy days, operators perform inspections and routine maintenance. Remaining workers perform maintenance duties full time.

Consumables for the system will be primarily concentrator washing solution. Washing solution consumption is estimated to be about 58,000 liters (15,000 gallons) per month; the solution makeup is primarily water. Other system consumables are low quantity.

The primary maintenance activity will be washing of concentrators. Using a special washing vehicle, the monthly washing process is anticipated to take about 15 minutes per concentrator, adding up to about 16 man-days per month. Other routine maintenance activities will include annual inspections of electrical equipment (switchgear, tranformer oil level, etc), concentrator reflective surfaces, etc. Scheduled overhaul of Brayton engines will be staggered such that only a few dishes will be inoperable at any given time.

Unscheduled maintenance will primarily involve repair of concentrator tracking mechanisms. An inventory of spare parts will be maintained.

Safety considerations for the Case 9 System are as follows.

- High voltage electrical system.
- Burns or eye damage from concentrators. This, in general, should not be a problem since the danger is primarily at the focal point of the concentrator. Safety procedures must be developed which assure that personnel will not be in a danger zone while concentrators are in or slewing to tracking conditions.

10.9.2 System Construction Considerations

The schedule for the design, procurement, and construction of the Case 9 System is essentially the same as for the Case 2 system; that schedule was previously given as Figure 10.2-3. Total elapsed time from initiation of preliminary specifications to initial plant operation is 24 months.

10.9.3 System Cost Estimates

A determination of Case 9 capital and O&M costs has been made; a summary of those costs, broken down by subsystems, is presented in Table 10.9-3. It can be seen that the collector subsystem constitutes a

TABLE 10.9-3. CASE 9 COST SUMMARY

Item		Capital Cost*
Land		175
Site Preparation		105
Collector Field		9,483
Concentrators (Installed)	7,236	
Receivers (Installed)	1,002	
Foundations (Installed)	1,245	
Electric Power Generation		4,182
Turbine/Generator	3,015	
Heat Rejection	392	
Installation	775	
Electric Energy Transport		2,809
Power Distribution	785	
Power Conditioning	750	
Installation	1,274	
Master Control		1,750
Balance of Plant		329
Subtotal		18,833
Contingencies (15 per cent)		2,825
Total Direct Costs		21,658
Indirects (25 per cent)		5,414
Total		27,072

Operations and Maintenance Cost: $382,000/year

Diesel Backup Package Capital Cost is $4,179,000.

*In thousands of 1980 dollars.

large share of the overall system cost (about 50 per cent). Key assumptions in the cost determination were as follows.

- Installed collector costs of $125/m^2$, based on manufacturers estimates.[5]
- Uninstalled receiver costs of $50/kWe; this was reduced from the Brayton receiver cost of $60/kWe used in Case 2 since no hybrid capabilities are included in Case 9.
- Uninstalled inverter costs of $75/kWe.[6]
- Uninstalled power conversion unit costs of $250/kWe plus $650/unit for heat rejection.[1]
- Electrical system costs based on a material takeoff for Case 9.
- Indirect costs include engineering and construction management fees, administration, plant start-up costs, and interest during construction.

10.9.4 Sensitivity Study

The Case 9 sensitivity study, like the Case 8 sensitivity study, examines the impact on system cost of increasing individual concentrator area by 25 per cent. Total reflective area is kept constant by reducing the number of concentrators by 25 per cent. Table 10.9-4 gives the resultant changes in cost for each subsystem.

Costs for land, site preparation, and balance of plant do not change since the land area, related to the reflective area, does not change. According to studies by Acurex[7] and by Ford Aerospace,[8] the 11 meters is the concentrator diameter having the lowest cost per unit reflective area; therefore the cost for concentrators increases. Costs of other system components, such as receivers, and turbine decrease on a per kW basis. The electric energy transport system costs decrease is somewhat due to reduced total cable length and a smaller number of terminations. The Master Control System cost decreases due to a fewer number of units to monitor and control.

10.9.5 Case 9 References

1. L. D. Six and others, Concept Definition Study of Small Brayton Cycle Engines for Disposed Solar Electric Power Systems, DOE/NASA/0069-79/1, January 1980.

TABLE 10.9-4. SYSTEM COST SENSITIVITY TO INCREASED CONCENTRATOR SIZE

Item	Baseline System	Large Dish System	Change
Land	175	175	0
Site Preparation	105	105	0
Collector Field	9,483	10,014	+531
Electric Power Generation	4,182	3,972	-210
Electrical Energy Transport	2,809	2,608	-201
Master Control	1,750	1,500	-250
Balance of Plant	329	329	0
Subtotal	18,833	18,703	-130
Contingencies and Indirects	8,239	8,183	-56
Total	27,072	26,886	-186

Costs are given in thousands of 1980 dollars.

2. Jet Propulsion Laboratory, Proceedings of the First Semi-Annual Distributed Receiver Systems Program Review, DOE/JPL-1060-33, April 15 1980.

3. Private communication to L. E. Stoddard, Black & Veatch, from Max Greeven, Project Engineer, AiResearch Manufacturing Company of California, August 25, 1980.

4. Private communication to L. .E Stoddard, Black & Veatch, from Lyle Six, Garrett AiResearch, March 4, 1981.

5. Private communication to M. D. Querry, Black & Veatch, from Roger Bedard, Acruex, February 23, 1981.

6. Private communication to L. E. Stoddard, Black & Veatch, from R. Rosati, United Technologies Corporation, September 12, 1980.

7. Private communication to L. E. Stoddard, Black & Veatch, from Roger Bedard, Acurex.

8. Ford Aerospace and Communications Corporation, Phase I of the First (Solar) Small Power System Experiment, Final Report, May 5, 1979.

10.10 CASE 10: DISTRIBUTED GENERATION VIA ORGANIC RANKINE CYCLE

The Case 10 system is defined to be a 10 MWe parabolic dish system, with distributed generation via organic Rankine cycle turbines. Three hours of thermal storage is located at each dish. The concentrator is selected from the GE and Acurex Low Cost Concentrators, which were used in Cases 7 and 8, respectively. The Case 10 system is located at Barstow, California, as a part of the Southern California Edison grid. As with the other cases, the design time frame is 1990.

10.10.1 System Description

The Case 10 system design has the following key characteristics.

- The organic Rankine cycle turbines used toluene as the working fluid at 427 C (800 F). The choice of toluene has been discussed in the previously given Table 10.1-1. The choice of the 427 C (800 F) pushes toluene to its limit.[1] Turbines currently being developed for parabolic dish applications will use toluene at 399 C (750 F) with upward adjustments made if experience justifies.[2]
- The Acurex Low Cost Concentrator will be utilized. The selection of the Acurex concentrator was discussed for Case 9 in Section 10.9.1.
- Storage (and the turbine) is located on the ground near the dish. A two tank series storage system, with a heat transfer salt (Hitec) as the receiver working fluid and the storage media, is utilized. Storage is at 454 C (850 F). Table 10.10-1 presents the rationale in selecting the storage concept.
- The power generated is rectified at each dish, transmitted as dc to one of 9 module collection centers, where it is inverted to ac, and stepped up to 4,160 volts for transmission to the grid connection at the field perimeter.

The system is sized such that the energy delivered by the solar receivers on a clear March 21 is sufficiently large to just fill the three hours of thermal storage, while the system delivers 10 MWe to the grid throughout

TABLE 10.10-1. CASE 10 STORAGE SYSTEM SELECTION

Design Decision	Supporting Rationale	Opposing Rationale
Storage located on the ground rather than dish focal point	Low cost concentrators not designed to support weight of three hours of storage at the focal point.	Locating on the ground requires flexible connections.
Series storage rather than parallel storage	Series storage gives a constant turbine inlet temperature; parallel storage turbine inlet temperature and power decreases when changed from solar to storage operation. Series storage better buffer of turbine from solar transient. Series storage is less complex.	Parallel storage allows direct input of receiver working fluid to turbine, giving lower receiver temperature for a given turbine temperature.
Molten salt rather than sodium	Molten salt is less hazardous in the case of leaks.	Sodium has a lower freeze point than salt (i.e., 98 C fcr sodium, 150 C for Hitech salt). Both require heat tracing. (Note: In Case 1 with a large amount of piping and its large surface/volume ratio this disadvantage of salts was much more significant than in Case 10). Sodium is less costly.
Molten salt versus heat transfer oils	High temperature capability of salt allows high turbine inlet temperature and high cycle efficiency. Silicone oils, which allow reasonably high operating temperatures, are extremely costly.	Oils do not freeze and therefore do not require heat tracing.

TABLE 10.10-1 (Continued). CASE 10 STORAGE SYSTEM SELECTION

Design Decision	Supporting Rationale	Opposing Rationale
Two tank versus single tank thermocline system	Two tank system is less complex. Two tank system does not suffer thermal degradation of thermocline.	Thermocline system is somewhat less expensive.
Rectification of ac generator output to dc for power collection. Subsequent inversion of power to ac.	Avoids problems of synchronizing all turbines. 60 Hz power generation necessary for synchronization requires gearboxes.	Larger cable sizes required for transmitting low voltage (200 vdc) than for higher voltage ac. Rectifier/inverter add to cost and have associated power losses.

the day. The system solar multiple (design point power from the receiver divided by power to the turbine) is 1.44.

10.10.1.1 System Design Requirements. This subsection presents specific design requirements for the Case 10 baseline system. Topics addressed include the following

- Site conditions,
- Site arrangement,
- System design point requirements,
- System functional requirements, and
- Standards and regulations.

Site Conditions. The site for the Case 1 system is in the vicinity of Barstow, California. It is assumed that the site selection can be made to minimize site preparation, erecting of electrical transmission lines, and other plant support items such as access roads. The previously given Table 10.7-2 lists site conditions assumed.

Site Arrangement. The physical arrangement for the Case 1 system is shown on Figure 10.10-1. The collector field covers 52 hectares (130 acres) and contains 864 collectors. The field is divided into nine electrical power collection modules, thereby reducing the length of the low voltage dc collector network. Power and control cables are direct buried along the routes shown. Inversion to ac and voltage step up are accomplished at each of the nine module centers. Control and maintenance facilities are located at the field perimeter.

System Design Point Requirements. The baseline system was designed to provide rated power (10 MWe) at noon March 21. Figure 10.10-2 shows the functional configuration of the system as well a identifying design point temperatures, pressures, flow rates, and power traces. Design details for the individual subsystems are listed on Table 10.10-2.

System Functional Requirements. The previous section on system design point characteristics has described the Case 10 system configuration as well as design point temperatures, flow rates, and powers. This section identifies various system operating modes and the functional roles of the various subsystems in achieving those modes.

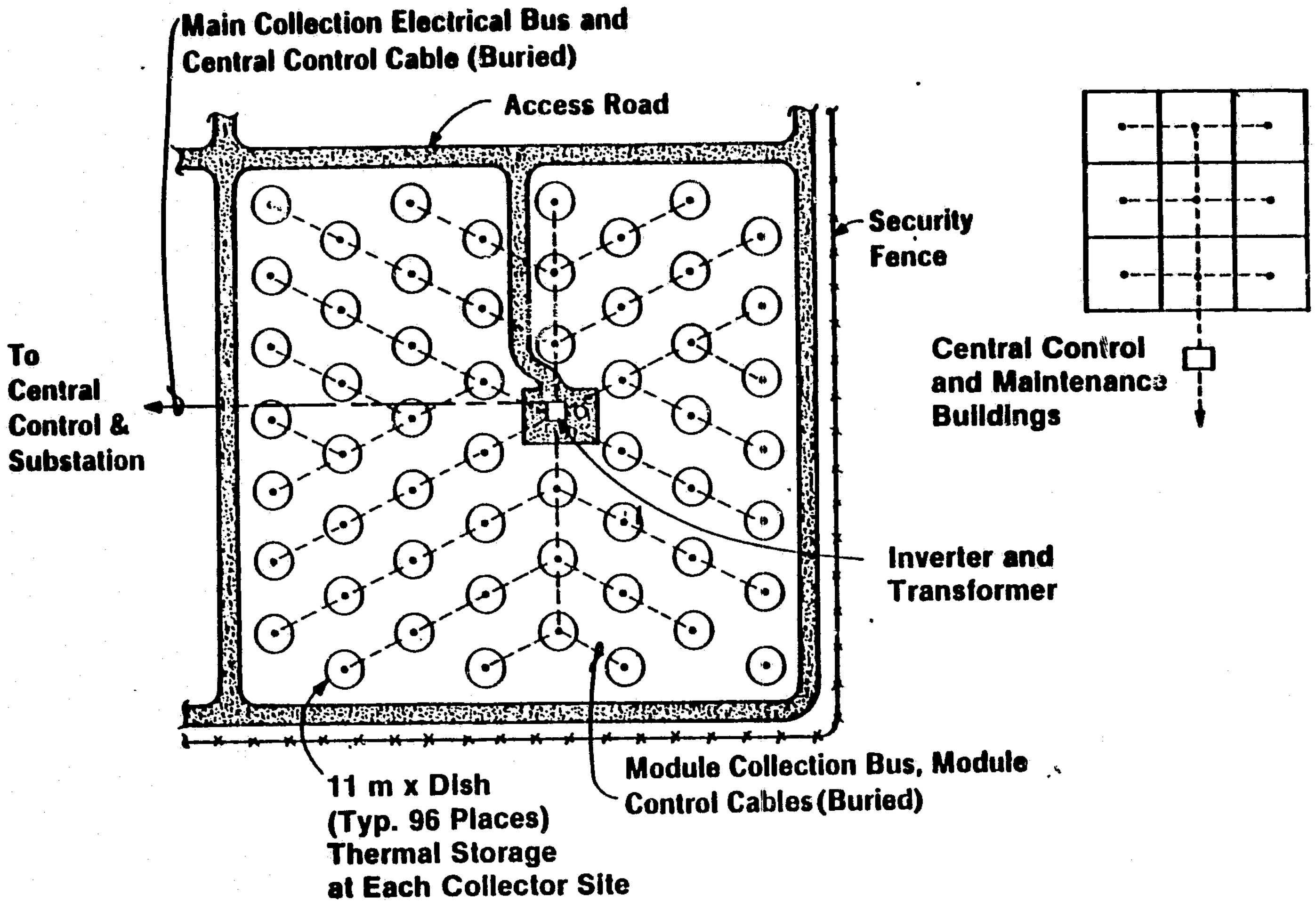


FIGURE 10.10-1 CASE 10 COLLECTION MODULE PLAN ARRANGEMENT

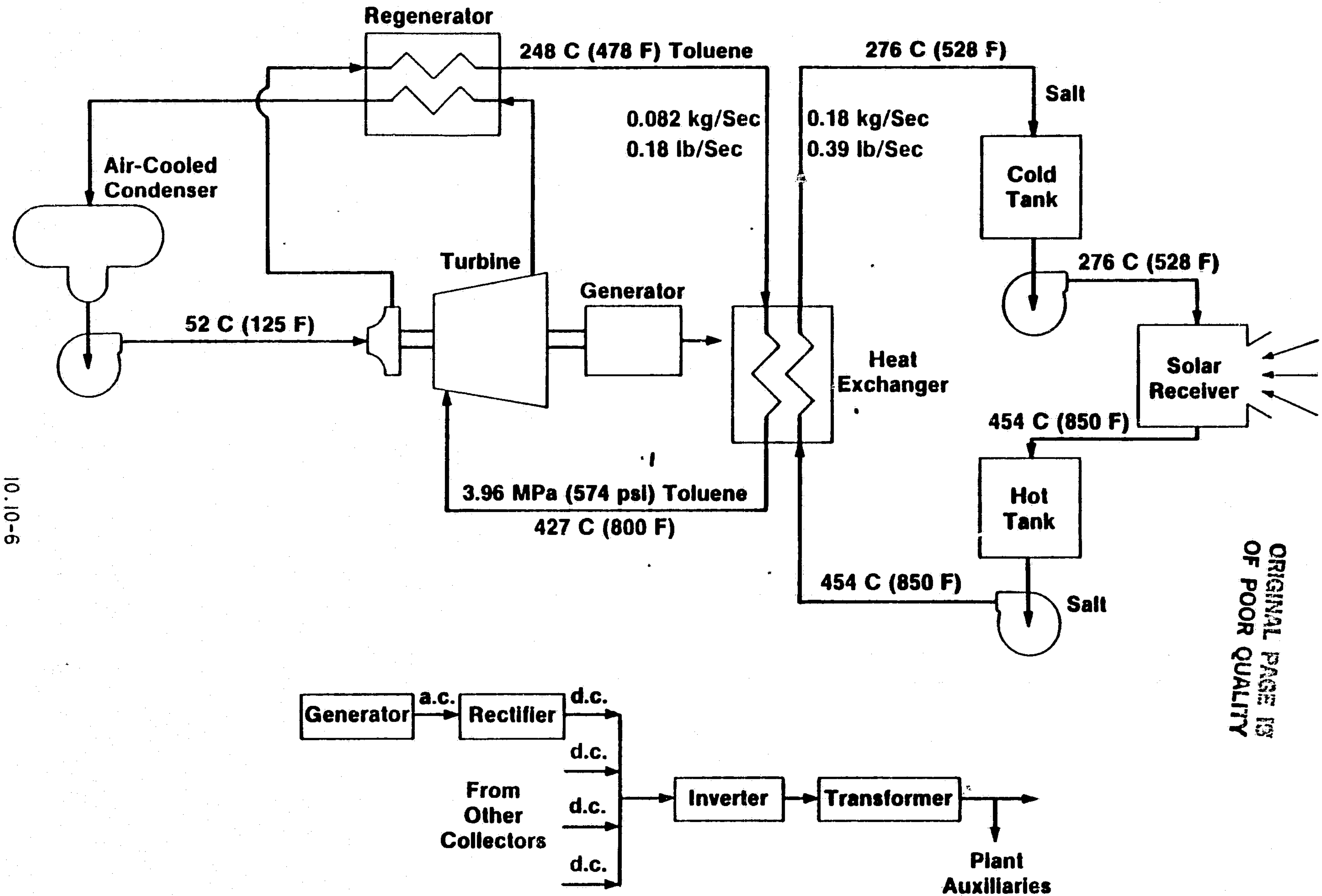


FIGURE 10.10-2 CASE 10 FUNCTIONAL FLOW DIAGRAM

TABLE 10.10-2. CASE 10 SUBSYSTEM DESIGN SUMMARIES

COLLECTOR SUBSYSTEM

Parameter	D. P. Value*
Concentrator[3]	
Dish Diameter, m (ft)	11 (36)
Effective Aperture Area, m^2 (ft^2)	95 (1,020)
Gap Loss Factor	0.919
Reflectivity	0.95
Blocking Factor	0.989
Shading Factor	0.998
Intercept Factor	0.95
Concentrator Effectiveness	0.819
Receiver	
Outer Diameter, m (ft)	0.75 (2.5)
Aperture Diameter, m (ft)	0.25 (0.8)
Weight, kg (lb)	227 (500)
Inlet Temperature, C (F)	276 (528)
Outlet Temperature, C (F)	454 (850)
Power into aperture, kWt (MBtu/h)	73.9 (0.252)
Power to fluid, kWt (MBtu/h)	71.1 (0.243)
Mass Flow, kg/sec (lbm/sec)	0.25 (0.56)
Efficiency	0.96
Radiation Losses, kWt (Btu/h)	0.7 (2,400)
Convection Losses, kWt (Btu/h)	1.3 (4,400)
Conduction Losses, kWt (Btu/h)	0.8 (2,700)

*Design point.

ELECTRIC POWER GENERATION SUBSYSTEM[2,4]

Parameter	D. P. Value*
Cycle	Supercritical ORC
Working Fluid	Toluene
Turbine Type	Single-Stage Axial Flow
Thermal Input, kWt (MBtu/h)	49.5 (0.169)
Cycle Efficiency	0.28
Turbine Inlet Temperature, C (F)	427 (800)
Turbine Inlet Pressure, MPa (psia)	3.96 (574)
Condensate Temperature, C (F)	52 (125)
Shaft Speed, rpm	60,000
Alternator Efficiency	0.92
Gross Electric Output, kWe	12.9
Net Effective Electric Output,** kWe	11.9
Boiler Toluene Inlet Temperature, C (F)	248 (478)
Boiler Toluene Outlet Temperature, C (F)	427 (800)
Boiler Molten Salt Inlet Temperature, C (F)	454 (850)
Boiler Molten Salt Outlet Temperature, C (F)	276 (528)
Toluene Flow Rate, kg/sec (lb/sec)	0.082 (0.18)
Molten Salt Flow Rate, kg/sec (lb/sec)	.18 (0.39)

*Design point.

**Effective electric output accounts for plant electrical auxiliary power requirements as well as line and inverter losses.

MASTER CONTROL SUBSYSTEM

- Central Control Mini-computer.
- Main Control Panel.
- Programmers Console.
- CRT Displays.
- Printer.
- Interface Hardware.
  - -- Turbine Controllers.
  - -- Storage Controllers.
  - -- Collector Controllers.
  - -- Energy Transport Controllers.
  - -- System Instrumentation.

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THERMAL ENERGY STORAGE SUBSYSTEM

Configuration	Two tank, series storage
Location	Each collector, on ground
Medium	Hitech (molten salt)
Capacity Per Collector, kWh_t (MBtu);h	150 (0.51); 3
Hot Tank Temperature, C (F)	454 (850)
Cold Tank Temperature, C (F)	276 (528)
Tank Dimensions	1.1 mϕ x 1.2 m (3.5 ft ϕ x 4 ft)
Tank Material*	Carbon steel
Hitech Inventory, kg (lbm)	1,950 (4,250)

*Carbon steel is used for salt containment whenever sufficient thickness can be attained to allow for corrosion. For thin-walled components, (e.g., heat exchanger) alloy steels are utilized. Processes such as aluminum diffusion on surfaces (e.g., alonizing) are being developed to resist corrosion.[5]

ELECTRICAL ENERGY TRANSPORT SUBSYSTEM

- General electric layout as per Figure 10.10-1.
- Collection of 200 vdc at nine central locations.
- Buried cable with EPR or XLPE insulation (as appropriate) and CSP Jacket.
- Nine 1,500 kVA solid state static inverters.
  - -- 200 vdc to three phase 480 vac.
  - -- 0.94 efficiency at rated load.
- Nine 1,500 kVA, 4,160 V/480 V transformers with outdoor enclosure.
- Switchgear and lighting protection.

BALANCE OF PLANT

- Buildings.
  - -- Central Control and Maintenance.
  - -- Warehouse (spare parts inventory).
- Maintenance Equipment.
  - -- Truck.
  - -- Crane.
  - -- Washing Vehicle.
  - -- Tools.
- Fire Protection System.
- Plant Lighting System.
- Roads.
- Security Fence.

The system has been designed for a rated net power output of 10 MWe. The storage capacity allows rated generation for three hours in the absence of solar power. Sizing of the system (number of dishes and relative dish/turbine sizes) is such that on a clear March 21, the system could be operated as shown in Figure 10.10-3a, or more likely, as shown in Figure 10.10-3b. System electrical output is limited to 10 MWe by turbine size. Figures 10.10-3c and 10.10-3d show conceptual system operation on clear summer and winter days, respectively. On summer days the energy from the collector is greater than can be utilized by the turbine and storage; therefore a "defocus" sequence must be utilized. On winter days the collector is unable to provide sufficient energy to both maintain 10 MWe generation and fill storage. Figure 10.10-3e shows operation on a cloudy day.

In achieving the above system operating modes the Collector Subsystem must fulfill the following functional requirements.

- Two-axis tracking of the sun.
- Heat molten salt from 227 C to 454 C (530 F to 850 F).
- Deliver up to 71.1 kWt (243,000 Btu/h) of power to the molten salt.
- Operate in winds up to 50 km/h (31 mph).
- Slew to stow in winds up to 80 km/h (50 mph).
- Survive in stowed position for winds up to 120 km/h (75 mph).
- Survive 0.35-g lateral seismic load.

The Thermal Storage Subsystem must fulfill the following requirements.

- Provide storage capacity to allow thermal input to each turbine for 3 hours operation at rated power.
- Accept charge rates from 3 kWt to 75 kWt.
- Provide discharge rates from 2.5 kWt to 50 kWt.
- Maintain molten salt quality and subsystem integrity.
- Provide for thermal losses to be less than 1 per cent of design point capacity per hour.

The Electric Power Generation Subsystem has the following functional requirements.

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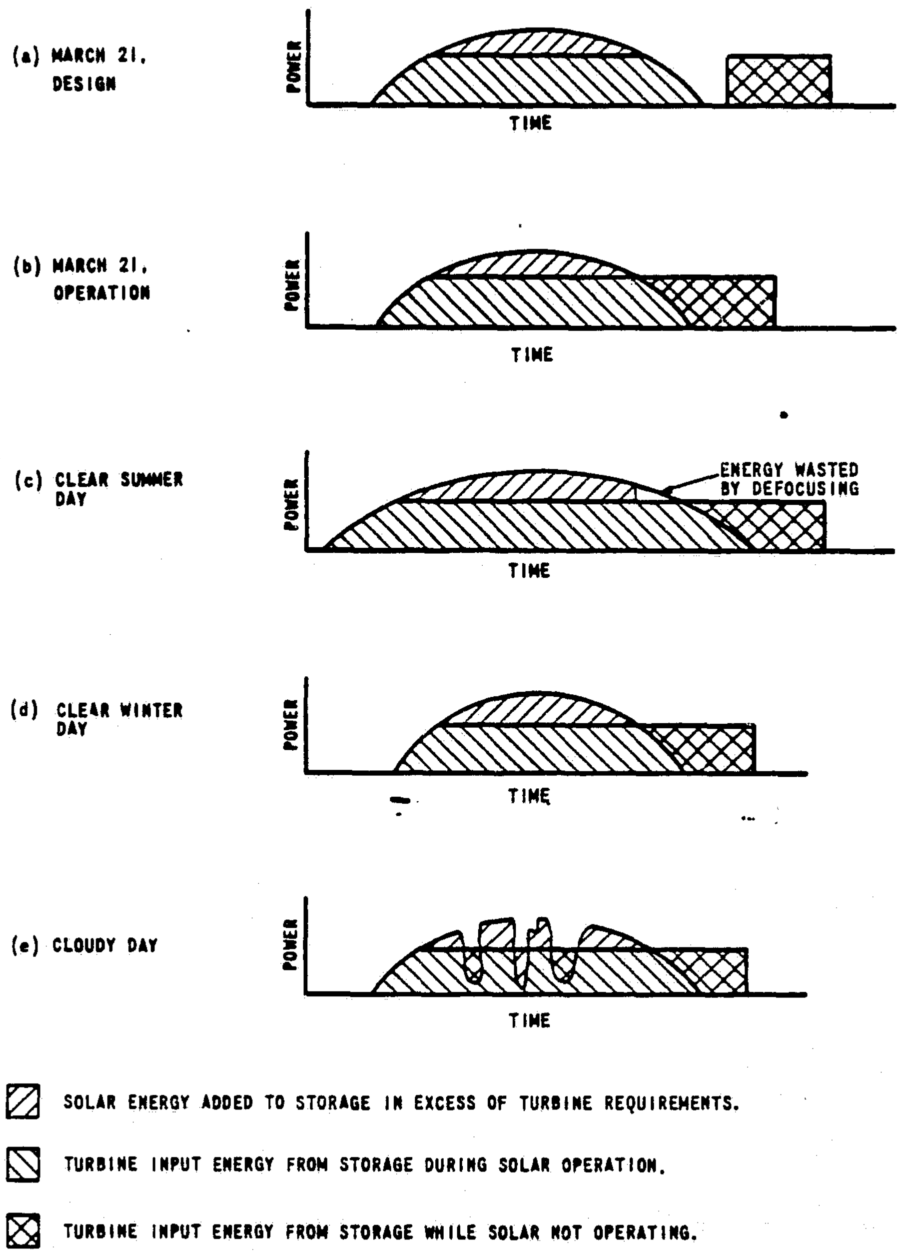

FIGURE 10.10-3. CASE 10 OPERATING MODES

- Transfer heat from molten salt at 454 C (850 F) to toluene at 427 C (800 F) at rates up to 3,300 kWt.
- Generate up to a gross power of 6 MWe (six modules).

The Energy Transport system must fulfill the following functional requirements.

- Collect up to 1.2 MWe at 200 dc at each collection center.
- Invert dc to three phase ac at 480 volts.
- Step up to 4,160 volts ac for transmission to the overall system output bus.
- Provide switching for isolation of collector modules and individual collectors.
- Provide lighting protection.

The Central Control System must fulfill the following functional requirements.

- Allow dispatcher control of turbine output power.
- Send command signals to individual collectors to track, defocus, or stow.
- Monitor energy in thermal storage.
  -- When storage is filled to capacity, to "defocus" collectors to match storage charge rate to its discharge and loss rates.
  -- Command all collectors to track the sun when the system can utilize the full output of the collector system.
- Monitor system temperature, pressures, and flows.
- Provide warnings and alarms for faulty operation.
  -- High temperatures and pressures.
  -- Indications of leaks.
  -- Salt freeze.
- Provide built-in automatic system start-up and shut-down algorithms for the collector field. The start-up algorithm must assure that thermal storage is not thermally degraded by premature circulation of molten salt through the collector field.

Standards and Regulations. The Case 10 system design is responsive to a number of laws, ordinances, codes, and standards. The previously given

Table 10.1-4 lists applicable regulations, along with the more significant impacts of those regulations.

10.10.1.2 <u>Operational Requirements</u>. The day-to-day operational factors of the Case 10 system consist of four elements.

- Personnel
- Consumables
- Maintenance
- Safety

Operations personnel required to staff the plant include six full time workers. Three of these workers are plant operators; duty hours are structured so as to cover average system operation 17 hours per day, 7 days per week. During cloudy days, operators will perform routine inspections and maintenance tasks. The remaining workers will be detailed solely to maintenance tasks, the chief task being washing of the collectors. No allocation of administrative personnel has been made.

The primary consumable for the system will be collector washing fluid. A wash and rinse method is proposed, with a total water usage of 79,000 liters (22,000 gallons) per month [the basis is 95 liters (25 gallons) per wash per concentrator and monthly washing]. Other consumables are low in quantity; lubricants, toluene make-up, nitrogen to provide a protective blanket for the molten salt, and nitrite make-up.

The primary maintenance activity will be the washing of concentrators. A washing vehicle which washes and then rinses the concentrator will be used. It is estimated that the cleaning process, which will be conducted once each month, will take 15 minutes per concentrator; this amounts to about 27 man-days per month. Other routine maintenance tasks will include inspection of system components for malfunctions (e.g., collectors for tracking problems). Corrective maintenance problems will primarily involve concentrator tracking mechanisms. An inventory of spare parts (electronics, cables, plastic panels) for concentrators will be maintained.

The primary safety concerns for the Case 10 plant are the fire hazard associated with toluene systems, possible burns or eye damage from concentrated solar radiation, burns from molten salt, or electrical shocks and

burns. The distributed nature of the toluene use (i.e., located only at each collector unit) minimizes the fire hazard to personnel. First, personnel are less likely to be in the region of a fire (as opposed to being in a turbine building as in Case 1). Second, personnel have more freedom of movement to avoid fires than if in a turbine building. Third, the size of such fires is likely to be smaller due to a smaller toluene inventory per unit.

Burns or eye damage from concentrators are unlikely because the danger is confined to the region of the concentrator focal point; safety procedures would prohibit personnel from entering that region while the concentrator is tracking the sun. Burns from hot salt system are minimized by insulation on all hot surfaces. Electrical hazards are minimized by proper design, construction, and maintenance techniques.

10.10.2 System Construction Considerations

Preliminary scheduling of the design, procurement, site preparation, and construction of the Case 10 System has been prepared. The total time period, from preliminary specifications through initial start-up, is estimated to be about 24 months. Figure 10.10-4 gives the construction schedule, detailing the various activity areas.

Assumptions used in preparing the schedule are as follows.

- A peak work force of 150 men is anticipated. This includes welders, dish erection crews, laborers, etc.
- An 8-hour day/20-day work month is assumed.
- Six four-man crews can assemble 24 dishes per week.
- Foundations for dishes are drilled and poured at 5-1/2 per day.

10.10.3 System Cost Estimates

Capital cost estimates for the Case 10 System have placed the system cost at $61,437,000 (1980 dollars). A breakdown of the various subsystem costs, along with assumed contingencies and indirect costs are listed in Table 10.10-3; estimated operation and maintenance costs are also included.

The bases for the various subsystem costs are as follows.

- An installed concentrator cost of $\$125/m^2$ was used, based on manufacturer's estimates.[3]

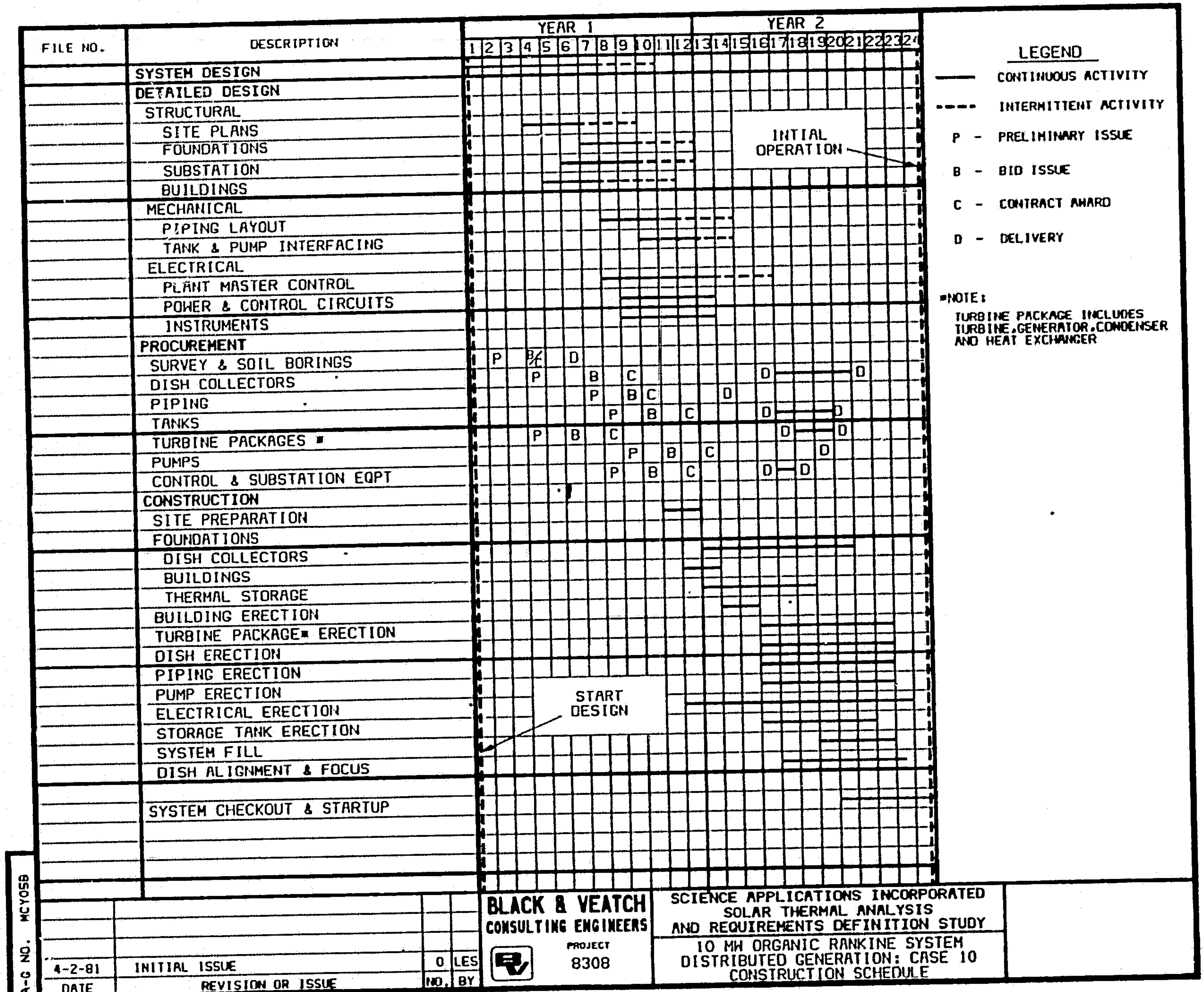

FIGURE 10.10-4 CASE 10 CONSTRUCTION SCHEDULE

TABLE 10.10-3. CASE 10 COST SUMMARY

Item		Capital Cost*
		$
Land		325
Site Preparation		195
Collector Field		13,849
Concentrators	$10,368	
Receivers	1,698	
Foundations (Installed)	1,783	
Thermal Energy Storage		11,289
Sodium	1,361	
Equipment	6,425	
Installation	3,503	
Electric Power Generation		9,316
Turbine/Generator, Regenerator, Condenser	5,573	
Salt/Toluene Heat Exchangers	2,590	
Installation	1,153	
Electrical Distribution		3,361
Material	983	
Inverters	750	
Installation	1,628	
Master Control		1,750
Balance of Plant		387
Subtotal		40,472
Contingencies (15 per cent)		6,071
Total Direct Costs		46,543
Indirects (32 per cent)		14,894
Total		61,437

Operations and Maintenance Cost: $920,000/year

*1,000's of 1980 dollars.

- Receiver costs of \$60/kWe were used, assuming a solar multiple of 1.0, and a turbine generator efficiency of 0.3 for the costing exercise. This is in agreement with DOE projections(6) and the Task 1 data base.(7)
- Power conversion unit costs of \$500/kWe,(4) excluding heat exchanger costs.
- Salt/toluene heat exchanger costs of \$3,000 per unit were used. Discussions with heat exchanger vendors and ORC turbine manufacturers failed to identify the existence of heat exchangers of the necessary size, operating conditions, etc. Preliminary estimates of heat exchanger costs ranged from \$2,000 to \$5,000 per unit.
- Other system costs were developed by the B&V cost estimating group from vendor information, B&V experience, and other published projects, based on first level material take-offs developed for the system design.
- Operation and maintenance costs are based on estimates from prior B&V solar projects, as well as published O&M projections for other projects.
- Indirect costs include engineering and construction management fees, administration and start-up costs, and AFDC.

10.10.4 References

1. W. M. Bohon, Black & Veatch, in personal communication to Doug Lacey, Sunstrand, August 22, 1980.
2. F. P. Boda, "The SCSE Organic Rankine Engine," Presented at the Parabolic Dish Solar Thermal Power Annual Review, Pasadena, California, January 13-15, 1981.
3. M. D. Querry, Black & Veatch, in personal communication to Roger Bedard, Acurex, February 23, 1981.
4. Jet Propulsion Laboratory, Proceedings of the First Semi-Annual Distributed Receiver Systems Program Review, DOE/JPL-1060-33, April 15, 1980.
5. S. L. Levy, Black & Veatch, in personal communication to Robert Carling, Sandia Laboratories Livermore, April 2, 1981.
6. L. E. Stoddard, Black & Veatch in personal communication to John Lucas, Jet Propulsion Laboratory, August 4, 1980.

7. Science Applications, Incorporated, <u>Solar Thermal Plant Impact Analysis and Requirements Definition Study</u>, Summary Report for Tasks 1, 2, and 3, JPL Contract 955238, September 7, 1979.

APPENDICES

APPENDIX A

SOLAR THERMAL ELECTRIC IMPACTS ANALYSIS METHODOLOGY OVERVIEW

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APPENDIX A

SOLAR THERMAL ELECTRIC IMPACTS ANALYSIS METHODOLOGY OVERVIEW

ABSTRACT

Widespread utilization of solar electric technologies will requi· integration with conventional utility generation. The interac between solar plant operation, backup requirements, and conve. utility generation have a major impact on solar system design and economics. Key considerations include the solar plant configuration, future fuel costs, utility production and capacity costs, utility load characteristics, conventional generation mix, and solar plant ownership options. This paper presents a methodology to evaluate design, performance, and cost relations for solar electric systems within the context of the overall solar/utility system interaction.

1. INTRODUCTION

Solar electric power systems have the potential to supply power for industrial, commercial, institutional, and utility applications and to reduce consumption of nonrenewable fossil fuels. In recognition of this potential, Science Applications, Inc. (SAI) is under contract to the Jet Propulsion Laboratory (JPL) to perform a comprehensive impacts analysis and requirements definition of solar thermal electric power systems. This study is part of the JPL Solar Thermal Power Systems Project, which supports the U.S. Department of Energy in the research, development, analysis, and application of point focus distributed receiver solar thermal systems.

Widespread utilization of solar electric technologies in the United States will require that the solar systems be operated in parallel with, or as supplements to, the existing utility grid. For such systems, assumptions regarding future backup electricity costs and utility costs have a major impact on solar system design and economics. Thus, in order to fully assess the economic worth of solar electric systems, it is necessary to evaluate their impacts on utility generation characteristics and to determine solar electric system design and cost relations within the context of the overall utility/solar electric energy supply system.

A comprehensive methodology (Young et al, 1979) has been developed to evaluate the impacts and economics of grid-connected solar electric technologies. Because solar energy varies both hourly and seasonally, reaching a peak level for only a few hours each year, solar generation is unique relative to conventional generation

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currently in use by most utilities. The value of solar plants integrated in a utility network is determined by both electric generation costs and also capacity costs required to meet a specific reliability level. Key variables include the mix and cost of conventional (non-solar) generation; the stochastic coincidence between solar generation and the electric system load; the amount of solar penetration; solar plant construction time and ownership; the energy storage capability of the solar system; and the solar system dispatch strategy. This paper summarizes the various techniques which have been developed and provides typical results for parabolic dish solar thermal electric systems.

2. METHODOLOGY OVERVIEW

Grid-connected solar electric systems have an impact on utility characteristics by modifying the load to be supplied by conventional generation. This provides direct economic benefits to the utility in the form of reduced fuel and operation and maintenance costs. In addition, the resulting load may also provide capacity savings in the form of reduced installed capacity requirements, depending on the statistical reliability of the solar generation during peak load periods. The modified load will also affect the appropriate utility generating mix of base, intermediate, and peaking plants. Figure 1 illustrates these impacts and the interactions between solar electric power systems and the utility network.

The model developed by SAI provides a comprehensive analysis of the impacts of different solar electric technologies, and estimates the economic value of the solar plants to the utility as well as to dispersed, non-utility owners. The final output of the model includes estimates for fuel and capacity savings to the utility, breakeven solar capital costs, and net present worth of the plant under different assumptions about ownership, payback period, discount rate, and solar system cost.

An overview of the model is shown in Figure 2. The overall assessment methodology involves five separate model segments—hourly simulation of solar electric system performance; utility load projection and adjustment for the output of the solar plants; capacity expansion and mix adjustment for conventional utility generation; production costing for the resulting conventional utility mix; and finally economic analysis of the solar plant value under different ownership alternatives. Because of the extensive calculations that are involved, the models have been implemented with a modular structure so that analysis runs can be made independently of the others. The various model segments are described in what follows.

3. SOLAR THERMAL ELECTRIC SYSTEM PERFORMANCE MODEL

The solar thermal electric performance model simulates the hourly output of various solar system/subsystem configurations. The performance model basically consists of subsystem component models which are used to compute steady-state efficiencies at each hour based on the ambient weather conditions and subsystem state variables. An overview of the model is shown in Figure 3. At each hour, the model computes steady-state energy balances, tracking losses, cosine losses, blocking and shading, reflectivity (or transmissivity), surface error losses, receiver intercept factors, receiver absorptivity, receiver re-radiation and convection losses, thermal transport losses, storage or hybrid energy flows, and part-load turbine generator efficiencies. Various dispatch strategies are available for storage and hybrid, including sun-following, load-shifting, peak shaving, level output, and different combinations of these for up to four time periods during the day.

Inputs for the solar plant model include the following categories:

- Hourly Meteorological Data on SOLMET Tapes
  - Beam and total horizontal radiation
  - Sun position
  - Temperature
  - Wind speed
  - Pressure
- Solar Electric Plant Data
  - Type (Parabolic Dish, Central Receiver, etc.)
  - Collector parameters
  - Energy conversion parameters
  - Subsystem efficiencies
  - Storage/hybrid configuration
  - Dispatch strategy
- Hourly On-Site Electric Demand Profiles.

Outputs consist of the annual energy flows to/from various subsystems, overall plant performance summaries, thermal energy credits (where applicable) and hourly electric output files for total generation and energy consumed on-site. The model outputs can be used directly for systems analysis and design trade studies, or the hourly output files can be attached for input to subsequent analysis models.

4. LOAD ADJUSTMENT MODEL

The load adjustment model estimates the impact of the solar electric generation on the overall utility loads. The original load for the utility is first projected to the time span of interest, and then the outputs of the solar electric plants are subtracted on an hourly basis, taking into account the transmission and distributed benefits of on-site generation and the possible forced outages of the solar plants. The hourly results are then accumulated in the form of load duration curves for each month or season, as indicated in Figure 4. These load duration curves are stored for both the original load projection (without solar) as well as for the load after solar is subtracted. This provides a non-solar reference case which is carried along with the solar case throughout the remaining analysis, so that the differential impacts of the solar generation can be accurately measured.

5. CAPACITY ADJUSTMENT MODEL

The capacity adjustment model performs a capacity expansion analysis to determine the type and number of conventional generating units which should be added to the existing utility

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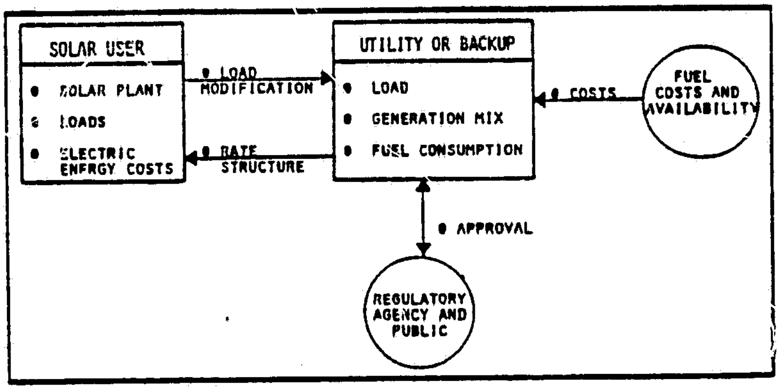

Fig. 1. Interactions between Solar User and Utility Backup

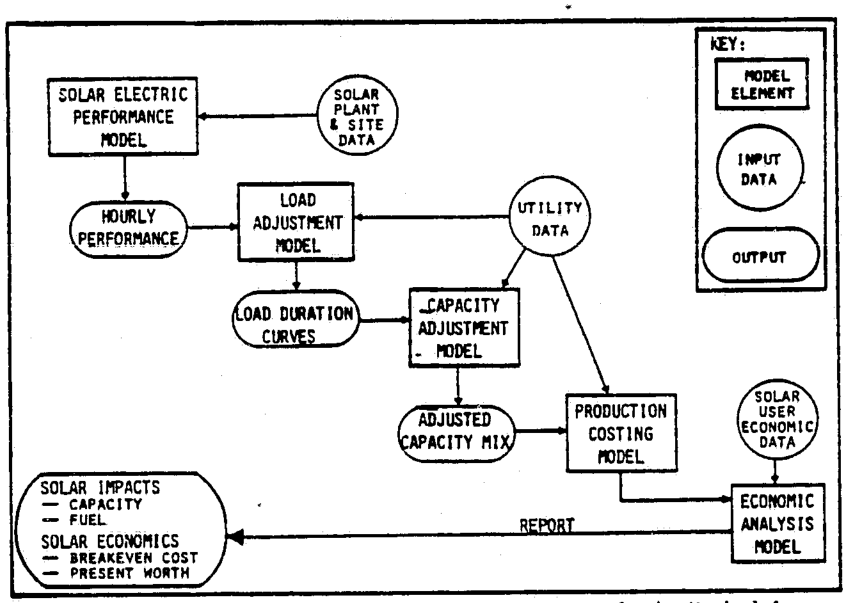

Fig. 2. Solar Electric Power Systems Impacts Analysis Methodology

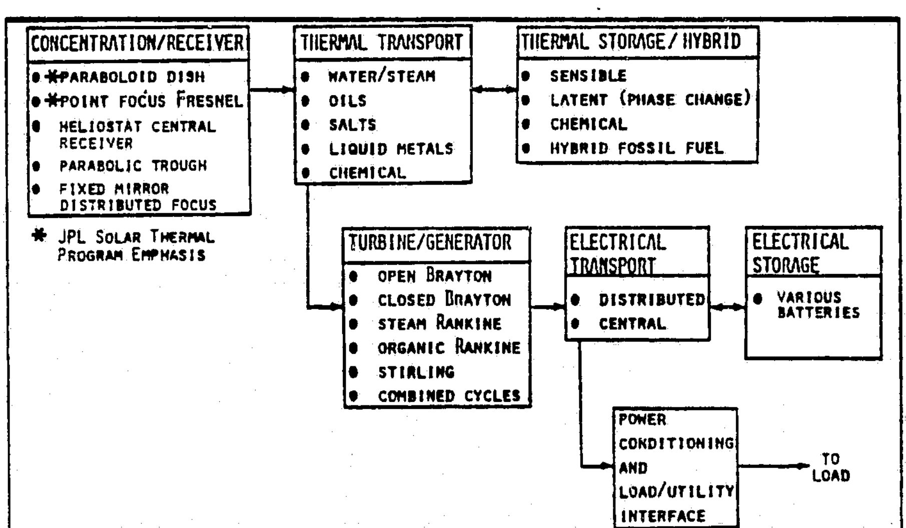

Fig. 3. Solar Thermal Electric Plant Performance Model

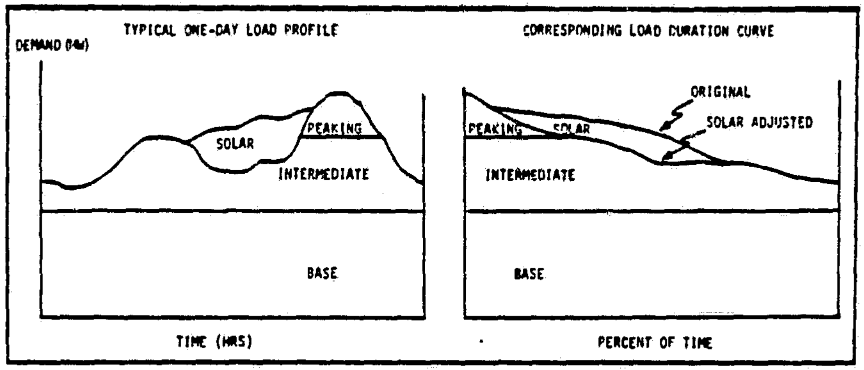

Fig. 4. Formulation of Utility Load Duration Curves

mix to meet projected electric demands at minimum total cost. This analysis is performed for both the solar case and the non-solar reference case. Inputs for the analysis include the existing utility system generating plants; the plants available for capacity expansion; characteristics of each plant type, including rated capacity, minimum operation levels, fuel type, heat rates, forced outage probabilities, maintenance requirements, fixed capital costs, and variable operation and maintenance (O&M) costs; utility economic data, such as fuel costs, escalation rates, taxes, discount rate, insurance, etc.; and projected utility load data in the form of seasonal or monthly load duration curves both with and without solar.

Figure 5 presents a screening curve analysis which illustrates the considerations involved in performing the utility capacity optimization. The upper curve shows annual costs for different plant types as a function of the number of hours per year which they are run; the lower curve represents the annual load duration curve. Capital-intensive plants such as nuclear or large coal have high fixed costs but low variable costs, so they are most appropriate when used as base-loaded plants that are run almost continuously. Combustion turbines, on the other hand, have low capital costs but high variable costs, so they are most appropriately used as peaking units which run only a few hours per year to meet the highest demand levels. By projecting the intersection points of the plant cost curves onto the load duration curve, as shown in the screening curve analysis of Figure 5, it is possible to estimate the amount of capacity desired for each plant type.

The screening curve analysis does not account for the previously existing plant mix of the utility, the discrete sizes of the available plants, or the probabilistic forced outage characteristics of the various plants. SAI has formulated the basic capacity expansion problem as a mixed-integer linear programming problem which is solved using a standard linear programming package. Figure 6 illustrates the discretization of the load duration curve into demand segments and the variable cost representation of each generator. The variables for the linear program are the number of plants of each type to be installed and the operating level of each plant in each demand segment. The objective function of the linear program is to minimize the present worth of total fixed plus variable plant costs, based on levelized annual cost data for each plant. Constraints for the problem include the following categories—installed reserve margin, demand requirements, plant operating constraints, plant availability and purchase constraints, plant energy limits (e.g., hydro), and integer variable constraints.

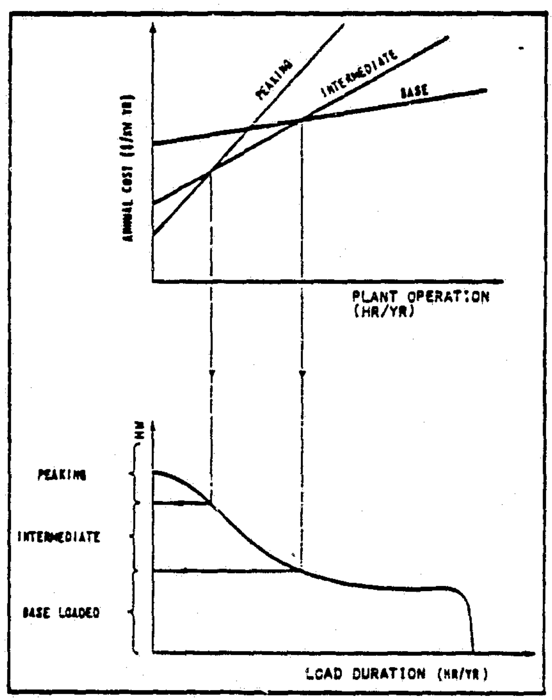

Fig. 5. Screening Curve Analysis for Capacity Optimization

The solution of the linear program provides the basic capacity expansion plan; however, it assumes de-rated plant capacities without accounting explicitly for the probabilistic nature of plant forced outages. This is performed in a subsequent analysis step, which estimates loss of load probability (LOLP) using a Gram-Charlier series expansion technique to rapidly evaluate convolutions of the demand and plant outage random variables. Peaking capacity is then added or subtracted from the generation mix to meet the required LOLP

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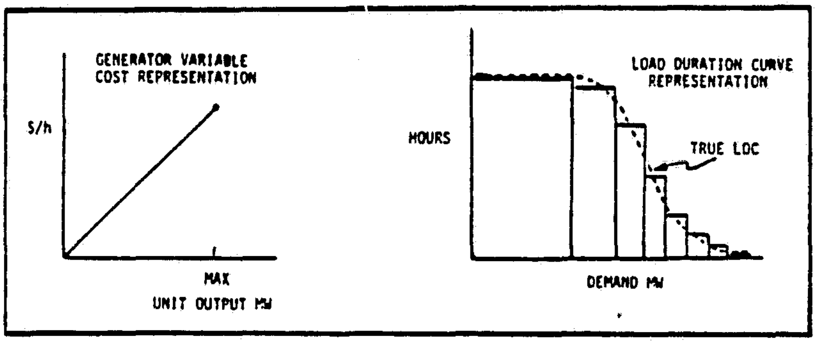

Fig. 6. Linear Programming Approximations

reliability criterion. The final output of the adjustment model is the adjusted utility capacity mix (both with and without solar), the estimated annual production costs for each generator type and fuel type, and an estimate of the present worth of revenue requirements for the utility.

6. DETAILED UTILITY PRODUCTION COSTING MODEL

A maintenance schedule is then estimated by removing plants according to maintenance requirements so as to levelize the reserve margin (defined as the ratio of total available plant capacity to peak demand). This schedule is input to a detailed probabilistic production costing model SYSGEN (Finger, 1979) which provides a refined estimate of production costs based on the modified load duration curves and the optimized conventional capacity mix (for both the system with solar generation and the reference system with no solar generation). SYSGEN uses the standard Booth-Baleriaux algorithm to account for plant outages, in which the effective load duration curve seen by each generator is expressed as the original load duration curve plus the random outages of previous generators in the loading order. The successive load duration curves are computed using a recursive technique to perform the required convolutions.

7. ECONOMIC ANALYSIS MODEL

The outputs of the detailed production cost model are then used to provide estimates of the breakeven costs of the solar plants for utility, on-site user, and third-party investor ownership alternatives. Additionally, the economic analysis calculates the net present worth of the solar system for various solar plant cost assumptions. A key assumption in the economic analysis for private owners is that the rate structure applied to solar system investors reflects the difference in cost of electric service to this customer class, so that the overall savings provided by the solar plants are passed on to the investor.

8. DISCUSSION OF RESULTS

A case study analysis was performed for parabolic dish solar electric systems interconnected with a large central utility in the southwestern region of the United States. The solar plant configuration was specified as 11 m diameter dishes with mirror reflectivity of 0.9, mirror slope error 3.5 mrad, reflected beam pointing error 3.5 mrad, and typical focal-mounted cavity receiver characteristics. The energy conversion system was an organic Rankine cycle turbine generator with a design point efficiency of 28 percent projected for 1990. Hourly SOLMET weather data for Phoenix, Arizona, was used to simulate solar system performance. The central utility included a mix of nuclear, coal, gas, oil, and peaking (combustion turbine) generation to meet a typical summer-peaking load of 6,329 MW in 1980 (reaching 10,310 MW in 1990). Utility capacity expansion and production costing were performed both with and without solar generation, the difference being the worth of the solar plants. Figure 7 presents typical results for the $/kW worth of solar generation per unit kilowatt as a function of solar penetration (total solar capacity as a percent of utility peak demand).

It can be seen that the primary value of the solar generation is as a fuel-saver, since displaced capacity (to meet the same LOLP) is small and consists largely of peaking units with low capital costs. Oil and gas constitute the largest fuel savings, with some displacement of coal usage at high penetration. The worth of the solar plant per unit kilowatt decreases with penetration level, particularly for solar plants with little storage and/or hybrid fuel capability. The solar plant breakeven cost at 10 percent solar penetration ranged from 2,400 $/kW for low-cost municipal financing to 500-1,000 $/kW for typical industrial ownership financing (utility savings are assumed to be passed back to the owners). Current JPL cost goals for 1990 are in the range of 1,600 $/kW. Similar analyses indicate that the worth of solar depends significantly on the plant design configuration (storage, hybrid, etc.), the solar penetration level (which will vary over time), the utility system configuration, and plant cost and owner financing considerations.

9. CONCLUSIONS

The methodology described above provides a comprehensive and consistent analysis of the economic worth of different solar electric technologies operating in a utility network. This is an important consideration in evaluating solar electric system design and cost relations

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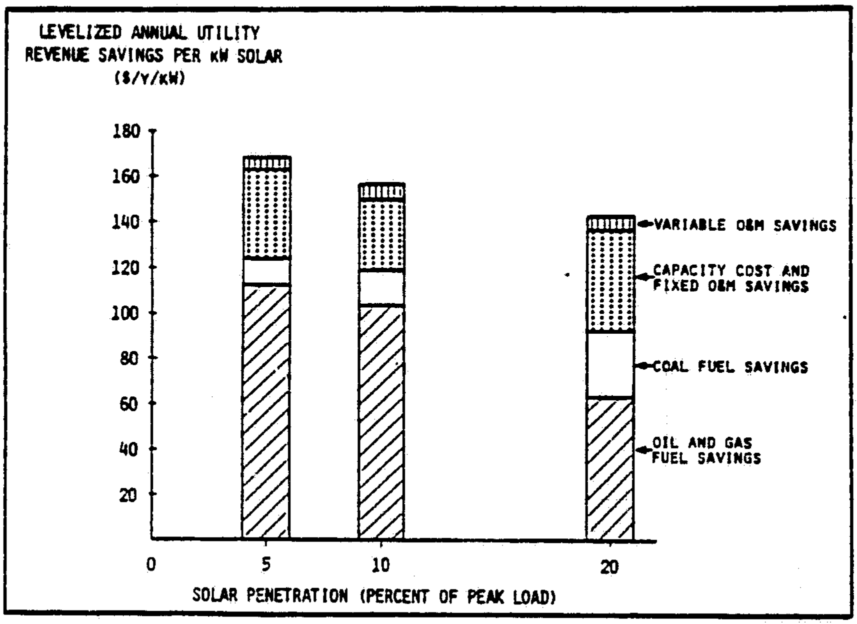

Fig. 7. Worth of Solar Generation to the Utility

within the context of the overall utility/solar system interaction. The methodology provides a systematic tool for analyzing the impacts, cost/performance characteristics, and design requirements of solar thermal electric power plants.

ACKNOWLEDGEMENT

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APPENDIX B

USE OF HYBRID FOSSIL/SOLAR SYSTEMS WITH LOAD DEPENDENT DISPATCH

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Section 1

LOAD-DEPENDENT SOLAR HYBRID DISPATCH

The use of hybrid fuel to increase the electrical output of the solar thermal electric power system was analyzed in the Task 5-8 Preliminary Case Study Report. Three hybrid dispatch strategies, 8 hour, 24 hour, and incremental dispatch were developed in the Report. None of the three strategies were found to be cost-effective for the small municipal and large investor-owned utilities.* In each case the cost of the hybrid fuel was greater than the benefits of the reduced requirements for conventional capacity and fuel usage. The purpose of this supplemental report is to analyze an alternative hybrid dispatch strategy, load-dependent hybrid dispatch, which makes more effective use of the hybrid fuel. An overview of load threshold hybrid dispatch is presented in this section followed by an analysis of the municipal and investor owned utility cases in Sections 2 and 3.

1.1 OPERATION OF LOAD THRESHOLD HYBRID DISPATCH

The load threshold hybrid dispatch strategy, unlike the strategies previously analyzed, uses the hourly load to determine when hybrid fuel is used. The key parameters are the hourly load $F(t)$ and the load threshold F_0. The load threshold represents the desired upper limit for the net load $F'(t)$ after the solar turbine is dispatched (i.e., $F'(t) = F(t) - T(t)$, where $T(t)$ is the hourly solar turbine output). Whenever $F(t)$ exceeds F_0, it is desired that the turbine output be sufficient to meet a differential load of $F(t) - F_0$. Otherwise, the net load will exceed F_0. If $T(t)$ from the solar system input alone is less that $F(t) - F_0$, the hybrid system begins operation. Sufficient hybrid fuel is used to increase $T(t)$ until it is equal to $F(t) - F_0$.

*In 1990, assuming use of distillate fuel for hybrid operation with a real escalation rate of 2.5 percent. It should be noted that hybrid would be more cost effective if residual oil were used (with pretreatment) as in conventional peaking generation.

Two restrictions limit the amount of hybrid fuel used. First there is a maximum turbine input capacity, T_{IMAX}. The hybrid fuel input may not increase the turbine input power above T_{IMAX}, even if T(t) is less that F(t) - F_o. In this case, the net load F'(t) will exceed F_o. The second restriction is the minimum solar input threshold T_{SMIN}. When the hourly solar input to the turbine is less than T_{SMIN}, hybrid fuel is not used. This restriction may be used as an option to improve the hybrid performance in the system. The solar input threshold can be set to maximize the increase in turbine output per unit of hybrid fuel. Because of the nature of the turbine power losses, the turbine efficiency curve increases very rapidly above a part load threshold point. The incremental efficiency of hybrid usage can be increased by requiring that the solar input alone be sufficient to operate the turbine at or above this threshold point. This type of incremental dispatch was discussed in more detail in Appendix B of the Task 5-8 Preliminary Case Study Report. Again, the total output is restricted by the turbine capacity, so that the solar-subtracted load F'(t) may exceed the desired level F_o during certain hours of insufficient turbine capacity.

The operation of the load threshold hybrid dispatch strategy for a typical day is illustrated in Figures 1 and 2.

Figure 1 illustrates the case where there is no solar input restriction. Before 9:00 in the morning, there is no solar input and the load F(t) is less than F_o, so no hybrid is dispatched. Therefore, the resultant load F'(t) is equal to F(t). From 9:00am to 10:45am, there is solar input, but the load F(t) is still less than F_o. Hence, F'(t) is less than F(t) by the amount T'(t), which is the turbine output without hybrid fuel. From 10:45am to 12:45pm, the load F(t) is greater than F_o; however, the turbine output T(t) without hybrid is greater than F(t) - F_o. In this period, no hybrid is required and F'(t) remains below F_o. From 12:45pm to 1:30pm, the load F(t) is greater than the desired threshold F_o, but T'(t) is less than the difference F(t) - F_o. Therefore, sufficient hybrid fuel is dispatched in this period to keep F'(t) at the value F_o.

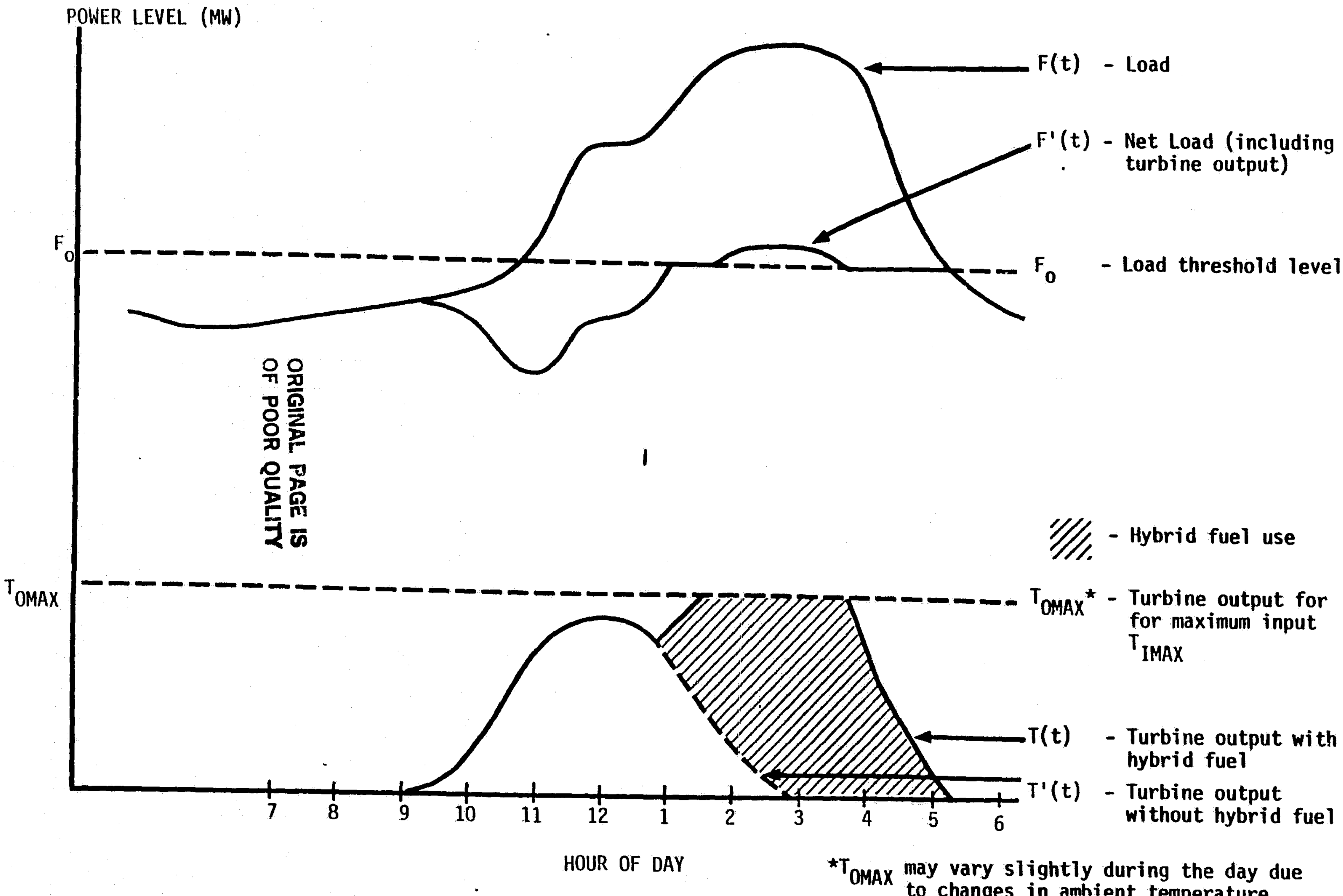

FIGURE 1. Load Threshold Hybrid Dispatch for Solar Plant

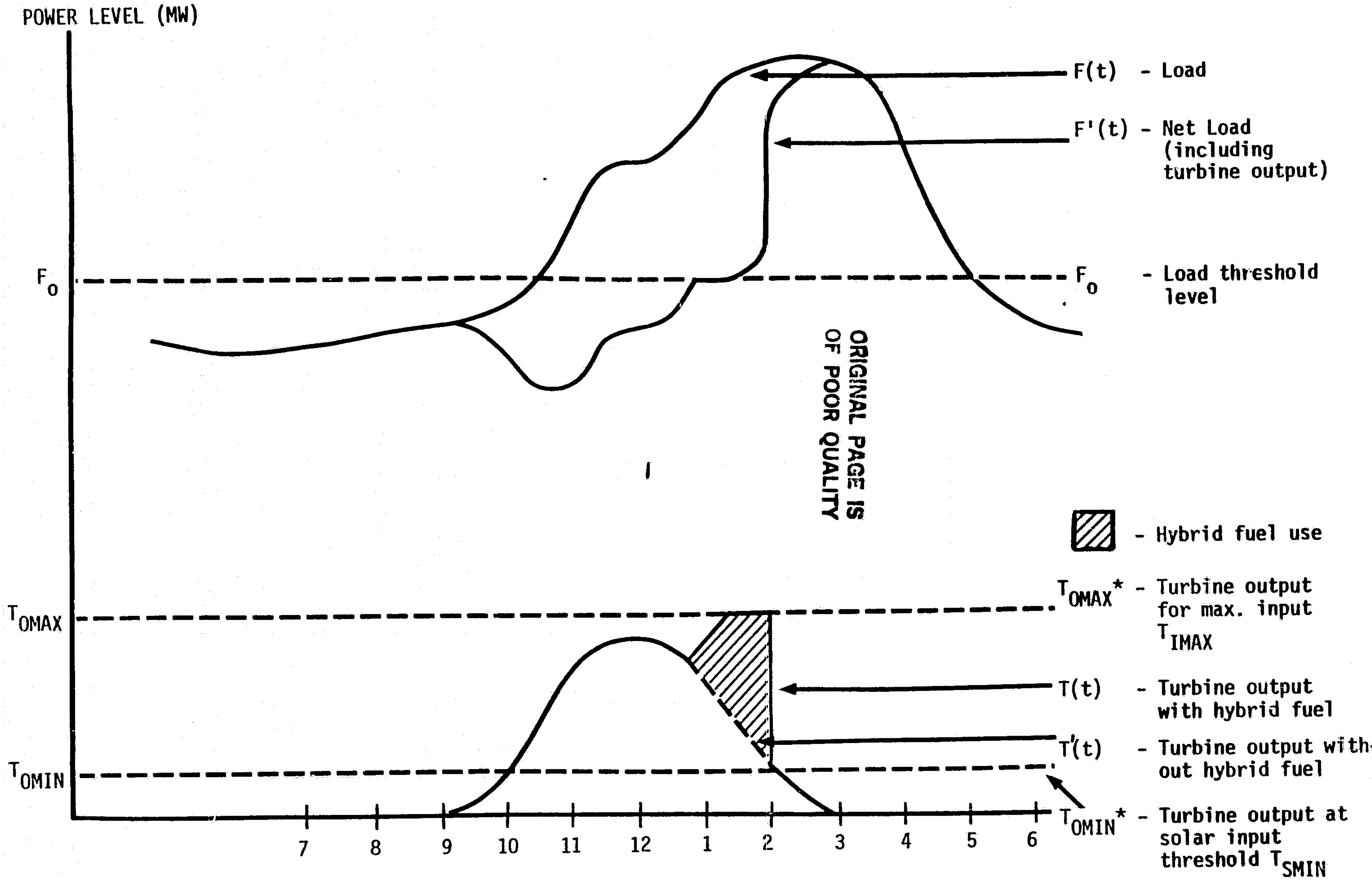

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FIGURE 2. Load Threshold Hybrid Dispatch with Solar Input Threshold Restriction for Solar Plant Turbine

From 1:20pm to 3:45pm, $F(t)$ is greater than F_0 and $T'(t)$ is less than $F(t) - F_0$, as in the previous period. Thus, hybrid is used, and in fact the turbine is run at its maximum capacity. The turbine output insufficient to bring the net load $F'(t)$ down to the desired level F_0. From 3:45pm to 5:15pm, the load $F(t)$ exceeds F_0, and there is no solar output. However, the load is less than it was for the 1:30pm to 3:45pm period, so that sufficient hybrid fuel may be used to reduce $F'(t)$ to the value F_0. After 5:15pm, $F(t) < F_0$, so no hybrid is used.

Figure 2 illustrates the case where there is a solar input threshold restriction T_{SMIN}. $F'(t)$ is the same as in Figure 1 until 2:00pm. After 2:00pm the solar input is less than the input threshold T_{SMIN}, so no hybrid fuel is used. Since the turbine output is small, the net load $F'(t)$ is greater than the desired level F_0 from 2:00pm to 5:15pm. After 5:15pm $F(t)$ drops below F_0.

A comparison of Figure 1 and Figure 2 illustrates the effect on conventional generating unit fuel usage and capacity displacement caused by the solar input restriction. Without the restriction, the peak net load is substantially less than the peak initial load. Therefore, a significant amount of conventional generating capacity may be displaced and the amount of conventional generating unit fuel usage will be reduced. With the restriction, the peak net load may be almost the same as the peak initial load, as shown in Figure 2. Therefore, the conventional generating unit fuel usage and capacity may not be reduced as substantially when the solar input restriction is in effect. On the other hand, the thermal-to-electric efficiency of the hybrid fuel usage is increased with the solar input restriction.

1.2 COMPARISON OF INCREMENTAL & LOAD-DEPENDENT HYBRID DISPATCH STRATEGIES

The discussion which follows provides a general comparison of the incremental dispatch and the load threshold dispatch strategies to illustrate the best uses for each and to clarify the results presented in this supplemental report.

The advantage in using the incremental hybrid strategy is that the efficiency of hybrid fuel usage as measured by turbine output is maximized. However, the incremental strategy does not take into account either the magnitude of the load, or more importantly, which conventional generating units must be operated to meet the load and maintain reserve requirements. This may result in the displacement by the hybrid fuel of a portion of the load which is served by a base level unit, such as a coal plant. The base units have fuel prices on the order of 1/5 the fuel price for hybrid fuel (Table 3-14, pg. 3-33, Task 5-8 Report). Therefore, in this case, the hybrid dispatch will displace the output of a unit which is less expensive than the hybrid to run. This is not a cost-effective use of hybrid fuel. The conclusion is that when coal or nuclear units are available, a load threshold limitation should be placed on the hybrid dispatch strategy to improve the economics of the hybrid fuel use.

The load threshold hybrid strategy may appear to reduce the energy generated by peaking capacity to meet the load, since the seasonal peak loads are reduced. However, it is not necessarily the peaking unit energy that is actually displaced. The use of solar may reduce the load peaks and the amount of installed peaking capacity sufficiently so that the total base and intermediate conventional generating unit capacity, excluding plants on maintenance, is greater than the seasonal peak load. The result is that peaking units will run primarily when the base and intermediate units have outages. Therefore, since the outages are random, the peaking unit energy cannot be displaced by hybrid through application of a seasonal or annual load threshold. In fact, since the peaking units cannot be displaced some displacement occurs for the base and intermediate units.

The peaking unit energy could be displaced to some extent by running hybrid in place of the peaking unit. This may not be possible however if the peak loads occur during the peak sunlight hours. At those hours during the months of peak insolation, the turbine would already be operating near its maximum operating point. Therefore, the addition of hybrid fuel would not increase the turbine output sufficiently

to meet the extra load requirements during a base or intermediate unit outage. If the peak loads during the year occur for the most part during the early morning, late afternoon, or evening, the use of hybrid in place of the peaking plants could be possible, if the solar penetration level is sufficiently high.

Even though the load threshold dispatch strategy may not remove peaking unit energy, it may still produce substantial savings compared to the no hybrid solar case. The savings may occur because of reduced base and intermediate installed capacity, with an actual increase in peaking capacity and use. Although the interaction of these factors is complex, several predictions may be made for the different utilities considered.

In the case of the small utility, such as the 60 MW utility case investigated here, the capacity credit constitutes a larger percentage of the net savings resulting from solar plant usage than the fuel savings. The base or intermediate unit capacity credit will therefore have a much greater effect on the total savings than the corresponding increase in peaking unit fuel cost and the additional hybrid fuel cost. In addition, the reduction in base and intermediate unit fuel costs will offset to some degree the extra peaking unit costs and hybrid fuel costs. Also, any reduction in total savings resulting from increased capital costs for installation of additional peaking units will be small. The reason is the capital costs of the base and intermediate units are several times the peaking unit capital costs. Therefore, for the small utility the net savings resulting from use of the load threshold hybrid strategy will be significantly greater than for the no-hybrid solar system.

On the other hand, for a large utility the capacity credit will be a small percentage of the net savings resulting from solar plant usage since the fuel costs represent a much larger percentage of the total savings. In this case, the additional hybrid fuel cost has a much greater effect on the total savings than base or intermediate unit capacity credit. Therefore, for the large utility the net revenues resulting from use of the load threshold hybrid strategy may actually be less than the revenues resulting from the use of solar without hybrid.

The following sections present analyses for the 60 MW municipal and 10,309 MW investor-owned utility for various levels of load threshold hybrid dispatch and solar input thresholds. Table 1 lists the cases of utility and solar system types which were analyzed previously (Task 5-8 Report) as well as the additional cases analyzed here. These analyses illustrate the problems and benefits discussed in this section in using the load threshold hybrid dispatch strategy.

TABLE 1. Selected Cases for Initial Analysis

LOAD SITE UTILITY DATA	CONFIGURATION DISPATCH / CYCLE	NS NH	2.5 HR STORAGE NH		5 HR STORAGE NH		NS HYBRID				2.5 HR STORAGE HYBRID
			TOD	SF	TOD	SF	8 h	ID	24 h	LT	DAY 8H SF
60 MW Fort Worth Municipal Utility (EPRI E Load)	BRAYTON	1									
	RANKINE	3		5	13	6	8	14	12	16*	10
10,309 MW Phoenix Invester-Owned Utility, EPRI E	BRAYTON	2					9			17*	
	RANKINE	4			7						
10 MW Phoenix Government Utility	BRAYTON	2**					9	15	11	18***	
	RANKINE										

Additional Cases

FOR ALL: Penetration Levels = 5, 10, and 20 percent.

Economic Analysis = Utilities, Industries, Instutional Users.

TOD = Time of Day Dispatch
SF = Sun Following Dispatch
ID = Incremental Hybrid Dispatch
NH = No Hybrid
NS = No Storage
LT = Load Threshold Hybrid Dispatch

*Various load and solar input thresholds

**Also for high penetration levels (>70%)

***Currently being analyzed

Section 2

MUNICIPAL UTILITY

This section describes selected impacts analysis results for the 60 MW peak load municipal case study for 1990 using a solar/hybrid system configuration with load threshold dispatch strategy. A range of hybrid dispatch options were evaluated using Fort Worth meteorological data, as in the Task 5-8 Report.

The following dispatch strategies were compared:

- No hybrid
- Seasonally varied* load threshold, 20 percent solar input threshold
- 90 percent seasonal load threshold, 20 percent solar input threshold
- 92.5 percent seasonal load threshold, 20 percent solar input threshold
- 97 percent seasonal load threshold, 20 percent solar input threshold
- Incremental hybrid dispatch (20 percent solar input threshold only).

The results are discussed in the following categories:

- Total solar system savings
- Capacity impacts
- Fuel usage
- Solar system breakeven cost
- Solar system net worth.

2.1 SOLAR SYSTEM SAVINGS

Total savings of fixed and variable conventional generation costs are summarized in Figure 3 (adapted from Figure 4-1, Task 5-8 Report) and Table 2 for various solar plant configurations and penetration levels. Savings are expressed in terms of levelized annual revenue savings to

*Load thresholds of 85 percent, Jan-Mar; 88.6 percent, Jul-Sep; and 87 percent, Oct-Dec to prevent hybrid displacement of available coal capacity not on maintenance.

Solar System Savings
Municipal Utility

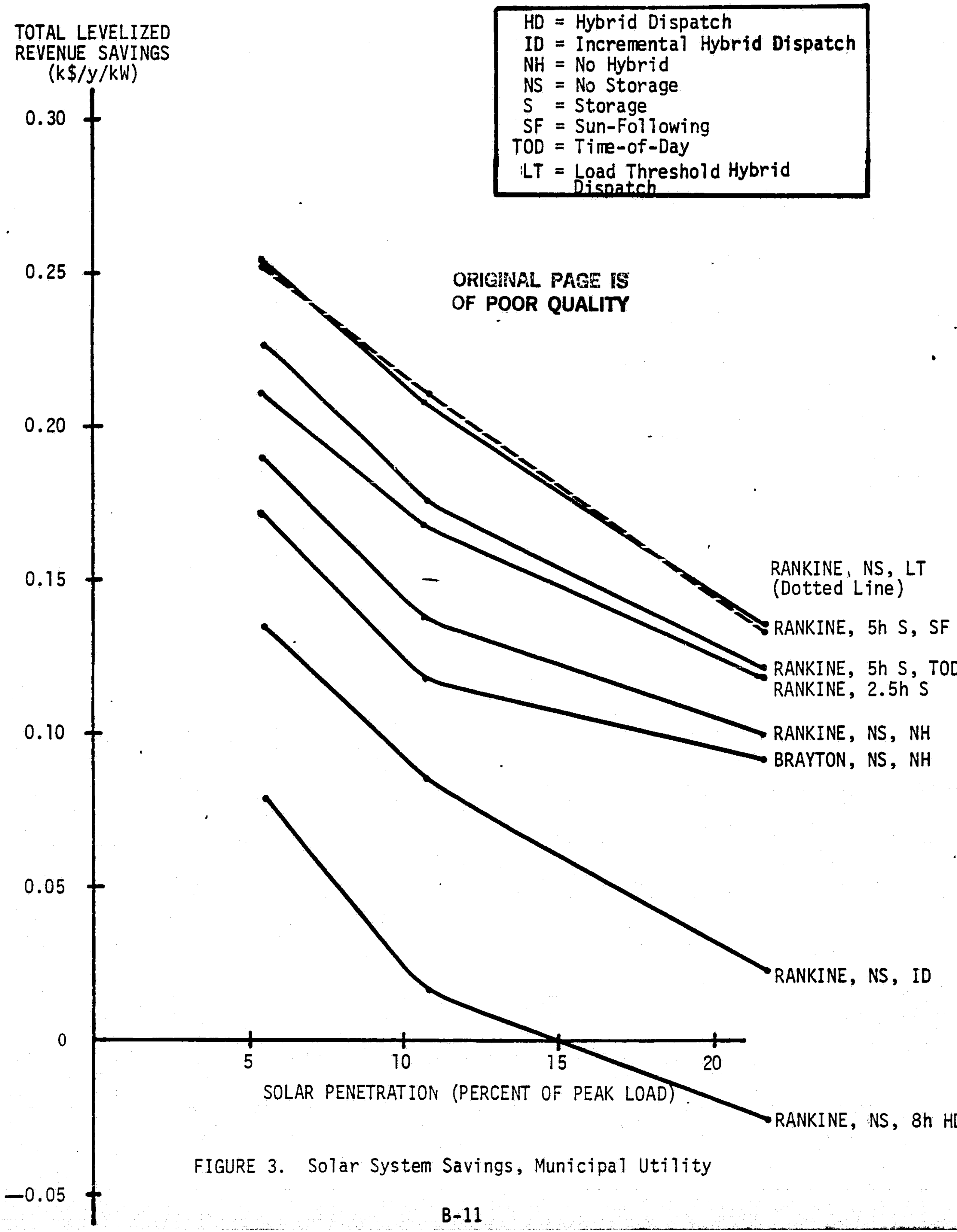

FIGURE 3. Solar System Savings, Municipal Utility

TABLE 2. Municipal Utility, Rankine, No Storage, 10% Solar Penetration, Levelized Annual Revenue Savings (k$/kW)

REVENUE SAVINGS BREAKDOWN	SEASONAL LOAD THRESHOLD/SOLAR INPUT THRESHOLD					
	NO HYBRID*	SEASONAL VARIATION** /20%	90%/20%	92.5%/20%	97%/20%	INCREMENTAL HYBRID*
TOTAL	0.137	0.210	0.194	0.192	0.192	0.084
CAPITAL	0.073	0.113	0.100	0.100	0.099	0.078
O&M	0.019	0.027	0.023	0.022	0.022	0.020
COAL	0.032	0.064	0.061	0.061	0.060	0.040
DISTILLATE OIL	—	-0.002	-0.002	-0.002	-0.002	-0.001
GAS	0.016	0.032	0.032	0.030	0.029	0.040
DIESEL	-0.003	-0.015	-0.015	-0.016	-0.017	-0.003
HYBRID FUEL	—	-0.009	-0.005	-0.003	-0.001	-0.090

*From Task 5-8 Case Study Report.

**Percent of Peak Seasonal Load: Jan-Mar 85%
Apr-Jun 88.6%
Jul-Sep 88.6%
Oct-Dec 87%

the utility per unit kW of solar generation. Figure 3 compares systems previously analyzed in the Task 5-8 Report with the most favorable load threshold hybrid system.

The load threshold levelized annual revenues are about the same as the revenues for the Rankine 5 hour storage system with sun-following dispatch. However, the added costs for storage are expected to be significantly higher than the addition of hybrid capability.* Therefore, the load threshold hybrid system appears to be more economically favorable.

The revenue savings for the different hybrid strategies are shown in Table 2. As expected, all the load threshold hybrid systems perform better than the no-hybrid system. The extra costs of the hybrid fuel are much smaller than the extra capacity credit that is gained and the reduced use of base and intermediate fuel.

2.2 CAPACITY IMPACTS

A comparison of the seasonal peak loads and the seasonal total available capacity, excluding the peaking units is shown in Figure 4 for the Rankine, no storage/no hybrid case at 10 percent solar penetration. For the utilities analyzed and for the time frame of 1990, the base capacity not on maintenance is significantly higher than the peak load in each season.** It is clear that the peaking units run primarily when the base and intermediate units have outages. Also, peaking unit capacity is not displaced (as discussed in Section 1.2). These effects are shown in Table 3, which provides a comparison of the installed capacity for the no-hybrid case and for the hybrid case with seasonally varied load threshold.

*The storage capital costs include specially insulated storage tanks, heat excahagers, the heat transfer fluids, the thermal transport system linking the storage system with the solar collectors and the turbine, and a control system for storage operation. In addition, storage costs include a vary significant cost for additional collectors (solar multiple greater than one) to provide thermal energy to be stored for later use. The hybrid capital costs include the fuel storage tanks and piping systems and the control system for hybrid operation. The levelized annual revenues include the cost of the hybrid fuel.

**This will not be true for all utilities. In addition, this may be different for the municipal and investor-owned utilities. The utilities may find it more cost effective to add peaking units rather than base and intermediate plants depending on the long term load forecast.

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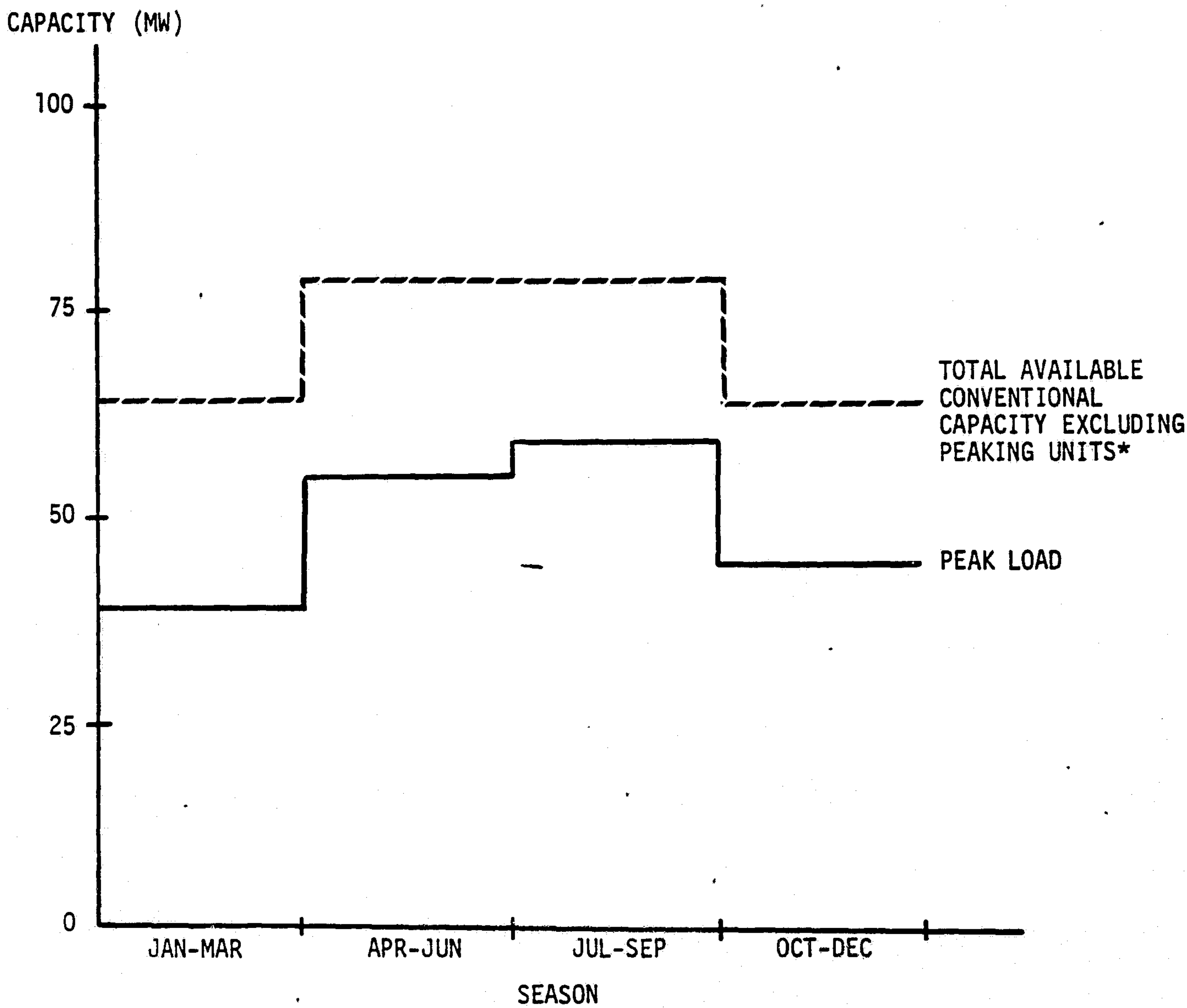

*Available = Not on Maintenance.

FIGURE 4. Peak Loads and Conventional Non-Peaking Capacity Which is Not on Maintenance, Municipal Utility, Rankine, No Storage, No Hybrid, 10% Solar Penetration

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TABLE 3. Municipal Utility, Rankine, No Storage, 10 Percent Solar Penetration, Conventional Generating Unit Capacity

GENERATING UNIT	NO HYBRID		LOAD THRESHOLD HYBRID 20% SOLAR INPUT THRESHOLD	
	CAPACITY (MW)	% OF TOTAL CAPACITY	CAPACITY (MW)	% OF TOTAL CAPACITY
COAL	48.88	56	47.12	56
OIL	15	17	15	18
GAS	15.26	18	14.06	17
DIESEL	7.40	9	7.48	9
TOTAL	86.54	100	83.66	100

TABLE 4. Municipal Utility, Rankine, No Storage, 10 Percent Solar Penetration, Fuel Usage (MWh)

FUEL	NO HYBRID	LOAD THRESHOLD HYBRID, 20% SOLAR INPUT THRESHOLD
COAL	267,400	257,500
OIL	19	78
GAS	19,473	17,739
DIESEL	1,717	2,179
TOTAL	288,609	277,514

The base and intermediate units (coal, oil, and gas) have increased displacement of capacity in the hybrid case, while the peaking unit (diesel) displacement remains essentially constant.

2.3 FUEL USAGE

Table 4 provides a comparison of the no-hybrid case and the hybrid case with seasonally varied load threshold for the Rankine cycle at 10 percent solar penetration. Since the capacity of the base and intermediate units is reduced by hybrid, thefuel usage by these units is reduced. Since the probability of an outage which reduces the total available capacity of the base and intermediate units increases, the total capacity of the diesel plants also increases (to meet the same reliability). Therefore, the fuel usage by the diesel increases slightly with hybrid. The reduction in the fuel usage by the base and intermediate plants is considerably higher than the additional fuel used by the diesel plant. In this case, the capacity reserve margin was high enough so that reduced base and intermediate plant capacity did not significantly affect the availability of base capacity. As discussed previously, this depends on the particular utility characteristics.

2.4 SOLAR SYSTEM BREAKEVEN COSTS

The solar system breakeven cost may be computed based on the total revenue savings to the utility summarized in Table 2. Figure 5 summarizes the solar plant breakeven costs for the load threshold hybrid system in the case of ownership by the municipal utility itself, as compared to systems previously analyzed in the Task 5-8 Report. The breakeven prices for the load threshold hybrid system are quite high, representing the highest net breakeven prices for all solar configurations. For example, at five percent penetration, the two highest breakeven prices are:

- Rankine, 5 hour storage $4.44/W
- Rankine, load threshold hybrid dispatch $4.38/W

as compared with $3.27/W for the no-storage/no-hybrid system. Detailed cost estimates for storage and hybrid have not yet been performed. However,

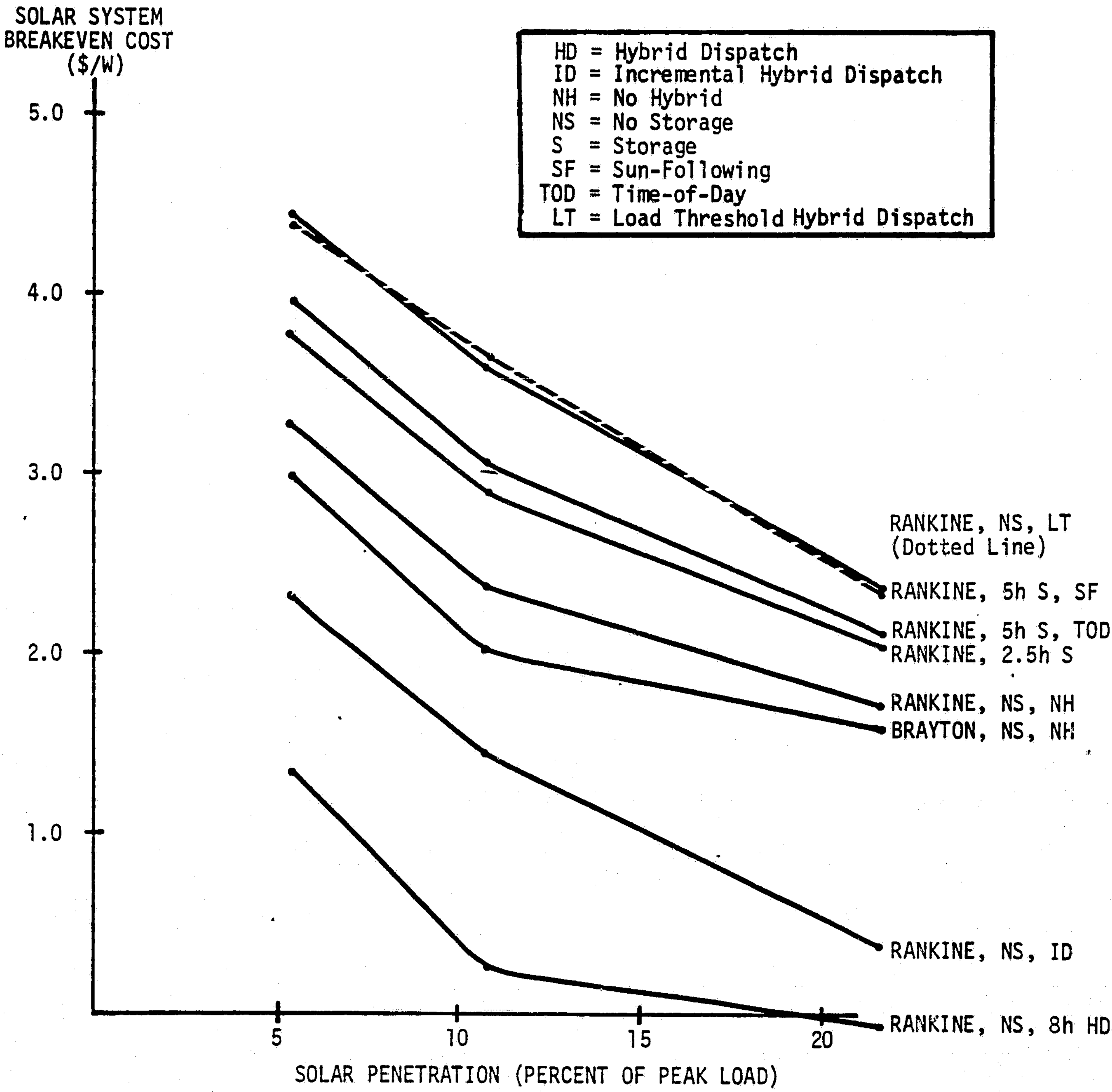

FIGURE 5. Solar System Breakeven Costs, Municipal Utility Financing

it is expected that the added cost of collectors for storage will be substantially higher than hybrid, so that hybrid is likely to be the preferred configuration (depending on oil prices).

2.5 SOLAR SYSTEM NET WORTH

A parametric system cost analysis was used to evaluate net solar system worth as a function of installed plant costs. Installed costs of $1,000/kW, $1,200/kW, $1,500/kW, and $2,000/kW were utilized in the analysis. Figure 6 shows the net worth of the Rankine no-storage, seasonally varied load threshold hybrid configuration as a function of penetration level for the various solar installed cost assumptions. At the low solar plant cost of $1,000/kW, the optimal penetration level is near 17 percent, decreasing to about 16 percent for $1,200/kW, 15 percent for $1,000/kW, and less than 15 for $2,000/kW. Therefore, (in the case of load threshold hybrid dispatch for the municipal utility) the optimal solar penetration level for a solar cost between $1/W and $2/W is approximately 15 percent of the peak load for the municipal utility. This compares favorably with incremental hybrid optimal penetration levels which were less than 5 percent for solar costs between $1/W and $2/W (Figure 4-10, pg 4-17, Task 5-8 Report). The substantial difference between the optimum penetration levels of the two hybrid systems is due to the different effect each hybrid system has on the conventional generating units. The incremental hybrid runs independently of the load and utilizes a substantial amount of fuel. Since the peaking units run only a small fraction of the time, the hybrid fuel primarily displaces less expensive coal or gas fuel unless the solar penetration level is low. On the other hand, the load threshold hybrid system displaces not only fuel, but also substantial capacity, so that the extra hybrid fuel cost is offset to some extent by the capacity credit. Therefore, the optimum penetration level may be higher for the load threshold hybrid system.

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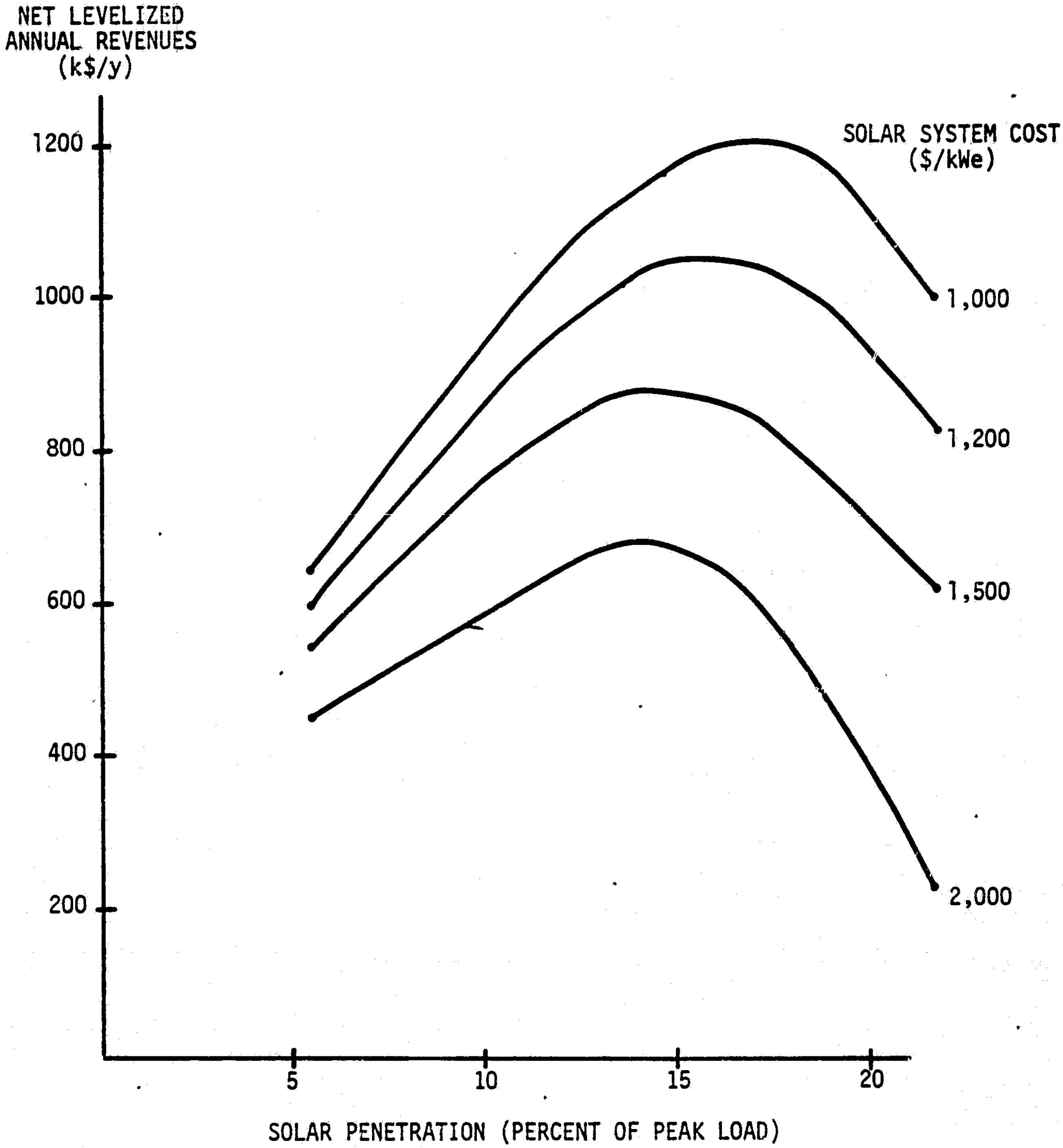

FIGURE 6. Solar System Net Worth—Municipal Utility Rankine, No Storage, Load Threshold Dispatch Hybrid

Section 3

INVESTOR-OWNED UTILITY

This section describes selected impacts analysis for the 10,309 MW peak load (in 1990) investor-owned utility case study using load threshold hybrid dispatch. A range of hybrid dispatch strategies were evaluated using Phoenix meteorological data, as in the Task 5-8 Report.

The following dispatch strategies were compared:

- No hybrid
- 94 percent load threshold, 20 percent solar input threshold
- 90 percent load threshold, 20 percent solar input threshold
- 85 percent load threshold, 10 percent solar input threshold
- 90 percent load threshold, 0 percent solar input threshold
- Incremental hybrid
- Peaking unit dispatch (in which hybrid capability is used solely as peaking generation and optimistically displaces all peaking capacity and energy generation used in the no-hybrid case).

The seasonal peak loads of the utility are compared to the seasonal total capacity of the available (not on maintenance) non-peaking generating units in Figure 7. The seasonal capacity is always substantially higher than the seasonal peak load, as with the municipal utility. Hence, the peaking units will run primarily when the base and intermediate units have outages. Also, as explained in the introduction, it is not possible using the load threshold dispatch strategy alone to displace only peaking unit capacity in this case.

The levelized annual revenues for the different hybrid strategies are listed in Table 5. As shown, the total levelized annual revenues for each of the hybrid cases are less than the revenues for the no-hybrid case. As discussed in the introduction, the reason for this is that for

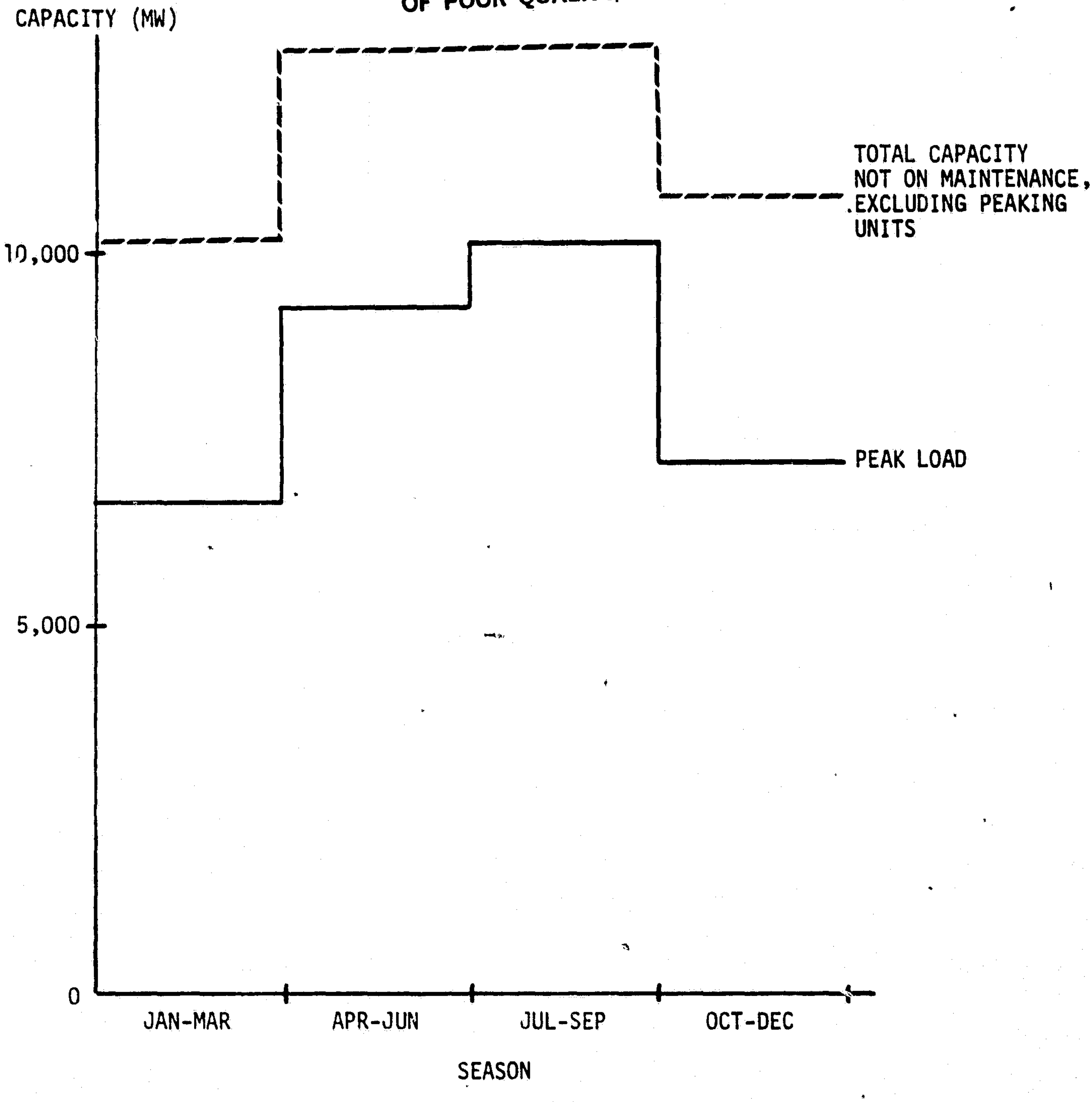

FIGURE 7. Peak Loads and Conventional Non-Peaking Capacity which is not on Maintenance—Investor-Owned Utility, Brayton, No Storage, No Hybrid, 10% Solar Penetration

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TABLE 5. Investor-Owned Utility, Brayton, No Storage, 10 Percent Solar Penetration, Levelized Annual Revenue Savings (k$/kW)

REVENUE SAVINGS BREAKDOWN	SEASONAL LOAD THRESHOLD/SOLAR INPUT THRESHOLD						
	NO* HYBRID	94%/20%	90%/20%	85%/20%	90%/0%	INCREMENTAL HYBRID	PEAKING UNIT DISPATCH
TOTAL	0.115	0.115	0.114	0.112	0.108	0.063	0.117
CAPITAL	0.011	0.011	0.011	0.012	0.013	0.013	0.014
O&M	0.010	0.010	0.011	0.011	0.012	0.012	0.012
COAL	0.013	0.013	0.013	0.014	0.014	0.015	0.013
RESIDUAL OIL	0.003	0.003	0.003	0.003	0.003	0.003	0.003
DISTILLATE OIL	0.001	0.001	0.001	0.001	0.001	0.001	—
NUCLEAR	—	—	—	—	—	—	—
GAS	0.076	0.077	0.078	0.081	0.082	0.084	0.076
HYBRID FUEL	—	-0.001	-0.003	-0.010	-0.016	-0.066	-0.001

*From Task 5-8 Case Study Report

a large utility such as this, the capital savings resulting from displacement of base or intermediate capacity is less than the extra fuel costs required by the hybrid system. In fact, as more hybrid fuel is used, the total levelized annual revenues are reduced, with the incremental hybrid (which uses the most fuel) having the lowest revenue savings.

Peaking unit dispatch of hybrid involves the use of hybrid capability whenever peaking generation would normally be used. Thus, the hybrid system displaces only peaking unit costs relative to the no-hybrid system displaces only peaking unit costs relative to the no-hybrid case. An estimate of the revenue savings for peaking unit hybrid dispatch is provided in the last column of Table 5. Total revenue savings are slightly higher because the hybrid capability is used only as a reliability credit with very little costly fuel consumption. This type of dispatch may not be technically feasible because of control problems and start-up lags in the solar hybrid system. It also assumes full capacity credit at the rated turbine power level and requires utility ownership with dispatch as a central generating plant.

In addition, the removal of the solar input threshold restriction reduces the revenue savings, as shown by a comparison of the 90 percent load threshold/20 percent solar input threshold system with the 90 percent load threshold/0 percent solar input threshold system. The main benefit for operation of the hybrid system without the solar input restriction is a 20 percent increase in capital cost displacement, which is expected since the turbine output may be used to reduce the peak loads whenever they occur as opposed to only during daylight hours. There are also slight increases in the gas and coal fuel displacement and the O&M displacement. However, reduction of the capital cost has only a small effect on the system economics because the capital cost revenue savings are only about 10 percent of the total revenue savings. In addition, the turbine is allowed to operate outside the optimal range of its efficiency curve, thus requiring substantially more fiel to produce the same output as the

system with the solar input restriction. As a result, the total hybrid fuel costs are more than five times the hybrid fuel costs for the system with 10 percent solar input restriction and so the net annual revenue savings are reduced. In summary, the use of the load threshold hybrid is not economically justified for the large investor-owned utility.

APPENDIX C

SOLAR THERMAL ELECTRIC DATA BASE AND PERFORMANCE MODELING

(SOURCE: TASK 1 REPORT)

APPENDIX C

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(Section 2 of Task 1 Report*)

SOLAR THERMAL ELECTRIC DATA BASE

Task 1 of this study entitled, "Solar Thermal Plant Impact Analysis and Requirements Definition," involves the development of a data base germane to the impact and requirements analysis of small (1 to 10 MW_e) solar thermal electric power systems (SPS). The principal elements of this task included:

- Identification of potential SPS concepts/configurations, and collection and screening of available data on their performance and cost characteristics
- Formulation of selection criteria involving considerations relevant to the technical and commercial viability of SPS designs, subsystems, components, and associated interface hardware
- Selection of SPS systems with the potential to produce competitive electric power in the near-term (1985-1989) and the long-term (beyond 1990) time period
- Formulation of appropriate parametric performance and cost models to permit execution of the required analyses.

The SPS system, considered in this study, is characterized by a solar collector (optical concentrator-receiver), an energy transport network, a heat engine, and a mechanically driven electric generator. An SPS plant may consist of multiple SPS modules, each generating about 15-25 kW_e (distributed generation), or a relatively larger heat engine powered by thermal energy from a field of interconnected solar collector modules (central generation). Either mode of generation may have a dedicated storage, a dedicated hybrid power source, or a utility hookup. The individual SPS plant will vary in size from 1 to 10 MW_e and could be deployed at various levels of aggregation and penetration.

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* This appendix is excerpted from the previously submitted Task 1 Report. Hence, all section numbers and figure numbers of this appendix are in reference to Section 2 of the Task 1 Report.

The emphasis of this task is on parametric modeling of potential SPS configurations and not on defining a priori their relative merits. Another area of emphasis was on Point Focus Distributed Receiver (PFDR) configurations although the data base was also generated in sufficient detail for SPS central receiver, FMDF and line focus systems. At present, proven systems for the individual SPS plant concepts do not exist although in some cases point designs have been developed and subsystem prototypes have been designed and tested. The implication of this state of knowledge regarding SPS technology is that the available information on cost and performance parameters is projective in nature and thus should be carefully utilized when estimating the future state-of-the-art parameters.

Much of the data on SPS parametric performance has been derived from information provided by the manufacturers of specific subsystems and related components, from in-house files of B&V and SAI, and from compilations developed by JPL and project reports completed under JPL, DOE/ERDA, EPRI, and private industry sponsorships. Contradictions that exist due to the diversity of objectives that these data were intended to serve have not been resolved. Their resolution will require continued analysis, design, development and testing studies.

2.1 SPS CONCEPTS/CONFIGURATIONS

A SPS plant consists of several subsystems, namely:

- Optical Concentrator
- Receiver
- Energy Transport

  } Collector Subsystem

- Energy Conversion (Heat Engine/Generator)
- Storage/Hybrid (if incorporated in the system)

The collector subsystem involves a concentrating mirror or a lens and a receiver on which the concentrating element focuses the sun's energy. Both the mirror and receiver are designed to withstand the operational and environmental loads. Depending on the mirror geometry and

configuration either the mirror or the receiver tracks the sun. Collector types include both the single-axis and two-axis tracking. An appropriate insulated piping network carries the heat transport fluid to transfer thermal energy from the receiver to the energy conversion unit. Energy transport modes in a SPS plant can be thermal, chemical, or electrical. Actual mode of energy transport depends on the generation mode (distributed, central) and the thermodynamic cycle incorporated into the SPS system. The distributed power generating concepts normally involve electrical transport from a field of individual power generator modules. The central power generation configurations typically utilize thermal or chemical transport of thermal energy to a single prime mover. Energy losses, both direct and parasitic, associated with either mode of transport need to be estimated to arrive at the proper energy transport subsystem design.

Energy conversion subsystem includes the turbine, pumps, condenser, heat rejection equipment, generator, switchgear, and associated controls. The main function is to convert thermal energy to electrical power which is properly conditioned for releasing into the user system.

Storage subsystem stores the excess energy available during periods of high solar insolation and releases the stored energy as needed in periods of low insolation. Not only does the storage system provide a capability for load management and a prolonged daily operation of an otherwise capital intensive system but it also reduces the adverse effect of solar transients on system components and operation. A hybrid SPS configuration involves an auxiliary generator (thermal or electrical source) which, depending on the output of the SPS, operates in conjunction with or in place of the SPS generator.

A variety of SPS system options with and without either or both a dedicated storage and hybrid configuration were considered in this study. The specific subsystem options included in the data base generated in Task 1 are listed below.

- Collector (Concentrator/Receiver) Subsystem
  - Point Focusing Distributed Receiver
    - Parabolic Concentrator
    - Circular Fresnel Lens
  - Heliostat/Central Receiver
    - Cavity Receiver
    - Exposed Receiver
  - Fixed Mirror Distributed Focus (FMDF)
  - Line Focusing
    - Parabolic Trough
    - Linear Fresnel Lens
- Energy Conversion Subsystem/Thermodynamic Cycle
  - Rankine
  - Rankine through Storage*
  - Open Brayton
  - Closed Brayton
  - Stirling
  - Combined Cycles
- Storage/Hybrid Configurations
  - No Hybrid, No Storage
  - Hybrid, No Storage
  - No Hybrid, Storage
  - Hybrid, Storage
- Energy Transport
  - Thermal } Central Generation
  - Chemical }
  - Electrical— Distributed Generation

Considering the stated available options for various subsystems, there are (4 x 6 x 4 x 1) or 96 possible SPS configurations for each mode of generation (distributed, and central). However, it is obvious that not all are equally economically attractive or technically feasible. Thus, a

*Although not a separate thermodynamic cycle, the through-storage configuration permits sufficient operational flexibility to warrant a separate listing.

set of selection criteria are needed to bound the number of configurations and select candidate SPS configurations for more detailed analyses.

2.1.1 Configuration Selection Criteria

The applicability and potential of any SPS configuration will be strongly dependent on the geographic region and energy user considered. Therefore, it is not practical to eliminate within the scope of Task 1 candidate systems based on preliminary cost/performance analyses. The set of criteria utilized for initial bounding of the SPS configurations consisted of:

- Technical feasibility
- Component availability during the 1985-2000 period
- Overall system rating, e.g., 1-10 MW_e systems with either distributed or central generation configuration

These selection criteria and their application to the possible SPS configurations are discussed in the following.

Technical Feasibility

Considerations pertinent to the tecl ical feasibility of any SPS configuration emerge from the inherent performance characteristics and limitations of the subsystems and components comprising the system. For example, a given thermodynamic cycle or heat engine has a specific range of temperature within which it can operate with an acceptable efficiency. Similarly, temperatures in the relevant range of operation of a given thermodynamic cycle may be obtained in a practical sense with only a specific type of solar collector. While, in theory, one has various options available in the energy transport, turbine, storage, and related electric generator and switchgear to be all centralized or dispersed, the inherent requirements of a thermodynamic cycle make one or the other mode of generation impractical. For example, high temperature thermodynamic cycles, such as Brayton and Stirling, could make centralized generation a more

costly alternative with the distributed collector systems when the heat losses, material requirements, pumping, and piping for energy transport to a central turbine are considered. Similarly, certain options, such as thermal storage for an Open Brayton system, are not feasible. The high temperature receiver outlet air is not a good heat transfer medium: Any attempt to transfer the heat to another medium, and to subsequently extract that heat into compressor discharge air would tend to result in a large loss in available energy and a greatly reduced cycle efficiency. Some of these aspects are discussed here in some detail.

Collector Performance Criteria

When numerous concepts require comparison, a collector performance criterion appears to be a simple measure of technical feasibility of various SPS configurations. In various studies, several types of concentrating collector concepts have been analyzed to define their performance levels. However, there has not been one basis of comparison in common to all of these analyses. For example, many investigators present noon-time efficiency levels, which are, of course, maximal values, while others present efficiency levels for 2:00pm solar time, while still others present whole day total levels of performance. In this study, we utilized as the basis of performance for all collectors analyzed, the whole day heat collection. The fundamental collector performance equation for whole day efficiency can be written as:

$$\eta_t = (\rho\tau\alpha)_e F_t - \frac{(Q_l/A_r)_t}{CI_{dn_t}} \tag{1}$$

where η_t is the whole day collector efficiency defined as a ratio of the whole day total heat collection per unit aperture to the whole day total direct normal insolation; $(\rho\tau\alpha)_e$ is the effective product of reflectance, transmittance, and absorptance of all optical elements which interact with each solar ray from its point of incidence with concentrator aperture until its absorption by the thermal receiver; F_t is the whole day average tracking efficiency, which includes the effects of cosine losses, blocking, shading,

and any other optical losses in the system; $(Q_l/A_r)_t$ is the whole day total heat loss per unit receiver area to the environment by radiation, convection, and conduction; C is the concentration ratio for the system, defined as (A_a/A_r)*; and I_{dn_t} is the whole day total direct normal insolation.

Equation (1) is an adaptation of the flat plate collector expression due to Hottel, Whillier, and Bliss, and later used for concentrating systems by Lof.[1] However, equation (1) is written for whole day collector performance rather than for instantaneous values, which has usually been the case in earlier studies.

Despite its simplicity, this equation permits evaluation of some of the interrelationships of the key variables related to collector configurations and the results can be utilized to eliminate the less attractive SPS configurations. For example, consider a fully tracking concentrating collector ($F_t \simeq 1.00$) utilizing some form of reflector with a reflectance (ρ) of 88 percent, and an open cavity receiver with an absorptance (α) equal to an emittance (ϵ) of 95 percent. Since the collector has no transmitting element, τ equals 1.00. Then the product $(\rho\tau\alpha)_e = 0.836$. Assuming that the cavity is highly efficient such that the conductive and convective heat losses are negligible relative to radiation losses to the surroundings at an ambient of 70°F during an entire operating day of 11 hours, a simple parametric analysis of the relationship between concentration, temperature, and whole day collector performance can be conducted. The results are shown in Figure 2-1 which utilized ASHRAE insolation data. Several conclusions are obvious from the data of Figure 2-1. First, the significance of very high concentration is minimal for low temperature collection, but increases with the increasing temperature. However, even at an operating temperature of 1000°F, typical of large conventional fossil fuel electric plant operation, an increase in concentration above a few hundred provides only a small improvement in full day collector performance. The collector performance, concentration, operating temperature, and cost interact in a complex manner since very high concentration systems can be anticipated to be more costly due to their increased complexity than lower concentration systems. Without a detailed evaluation of this relationship between collector

* A_a is the concentrator aperture area, A_r is the receiver aperture area.

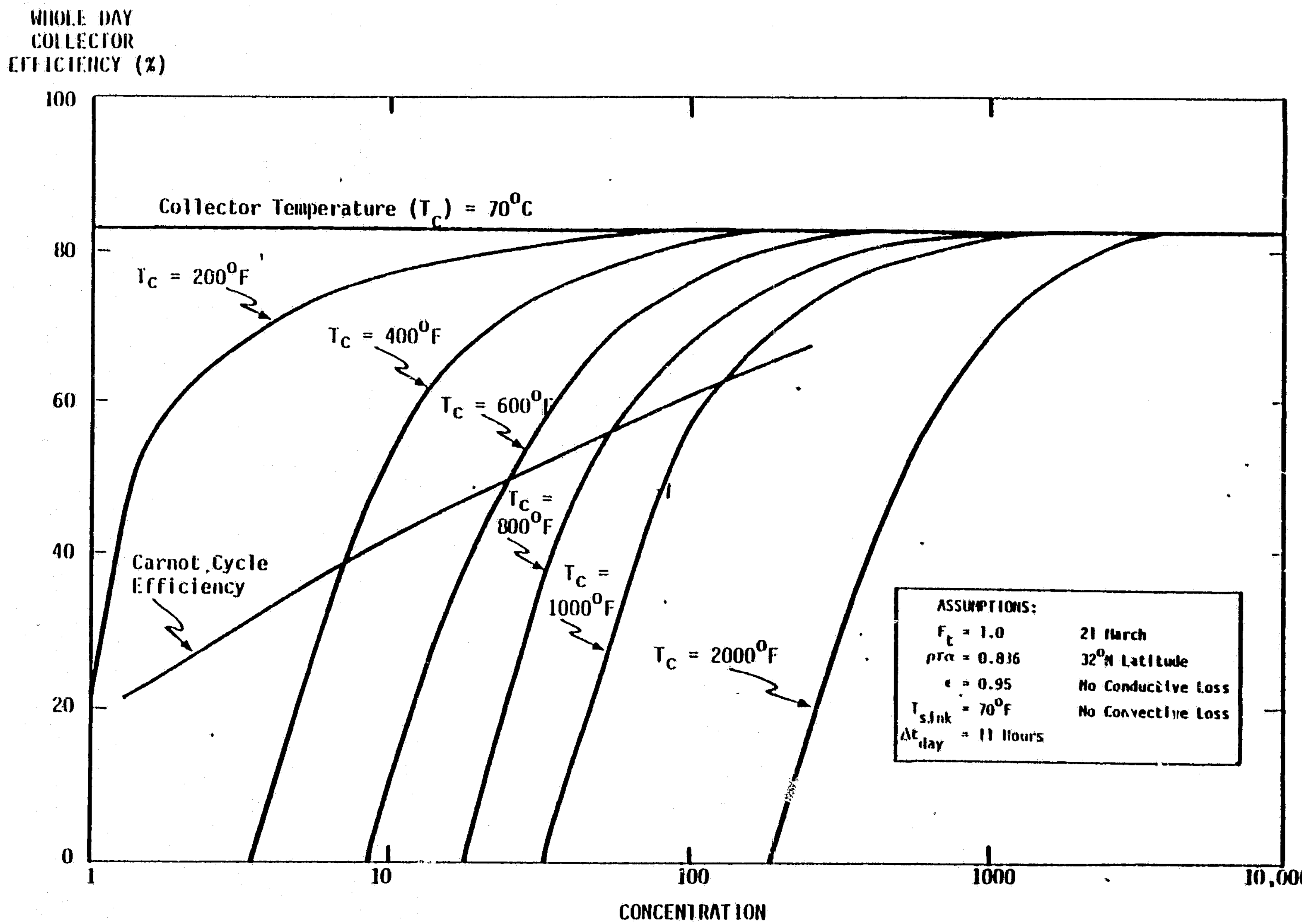

FIGURE 2-1. Whole Day Collector Efficiency versus Concentration for Various Operating Temperatures (not including convection or conduction losses)

characteristics, the performance of collector systems cannot alone be used as a guide to eliminating certain SPS configurations. However, if one superimposes on collector performance the characteristics of various heat engines, Figure 2-2, it is apparent that only certain collector types can be adapted in a practical sense to the requirements of specific heat engines. For example, a Brayton or Stirling cycle requires a minimum operating temperature of around 900°K (1200°F) which requires point focusing collectors, see Figure 2-3 together with Figure 2-1. An organic Rankine cycle requires at most 700°K (800°F) and thus can operate from point and line focusing collectors. This consideration alone reduces the number of possible SPS configurations to (2 x 4 x 4 x 1) + (4 x 2 x 4 x 1) or 64 for either mode of generation.

Another observation to be made from Figure 2-1 is that for a specific collector with a fixed concentration there exists an optimal temperature of operation to yield a maximum product of collector and cycle efficiencies. This effect is illustrated in Figure 2-4 for Carnot efficiency and concentrations of 100 and 500. This is so because the collector efficiency drops with increasing collector operating temperature while cycle efficiency increases, thereby ensuring an optimum value of the product of two efficiencies at some temperature level. This effect will prevail even with real heat engines that approach the Carnot efficiency within some reasonable limit (perhaps 50 to 70 percent of Carnot efficiency). This characteristic of collector-heat engine performance does not by itself allow further elimination of less desirable SPS configurations. However, it appears that when specific generic applications are considered under Task 2, elimination of less attractive SPS configurations—application pairs could emerge on the basis of the collector-heat engine performance characteristic discussed above.

Another collector performance characteristic that will permit ranking of SPS configurations from most desirable to least desirable is shown in Figure 2-5 which shows the effect of change in optical efficiency factor, $(\rho\tau\alpha)F_t$, on the whole day collector efficiency at various optical concentrations and collector operation fixed at 1000°F. It is apparent

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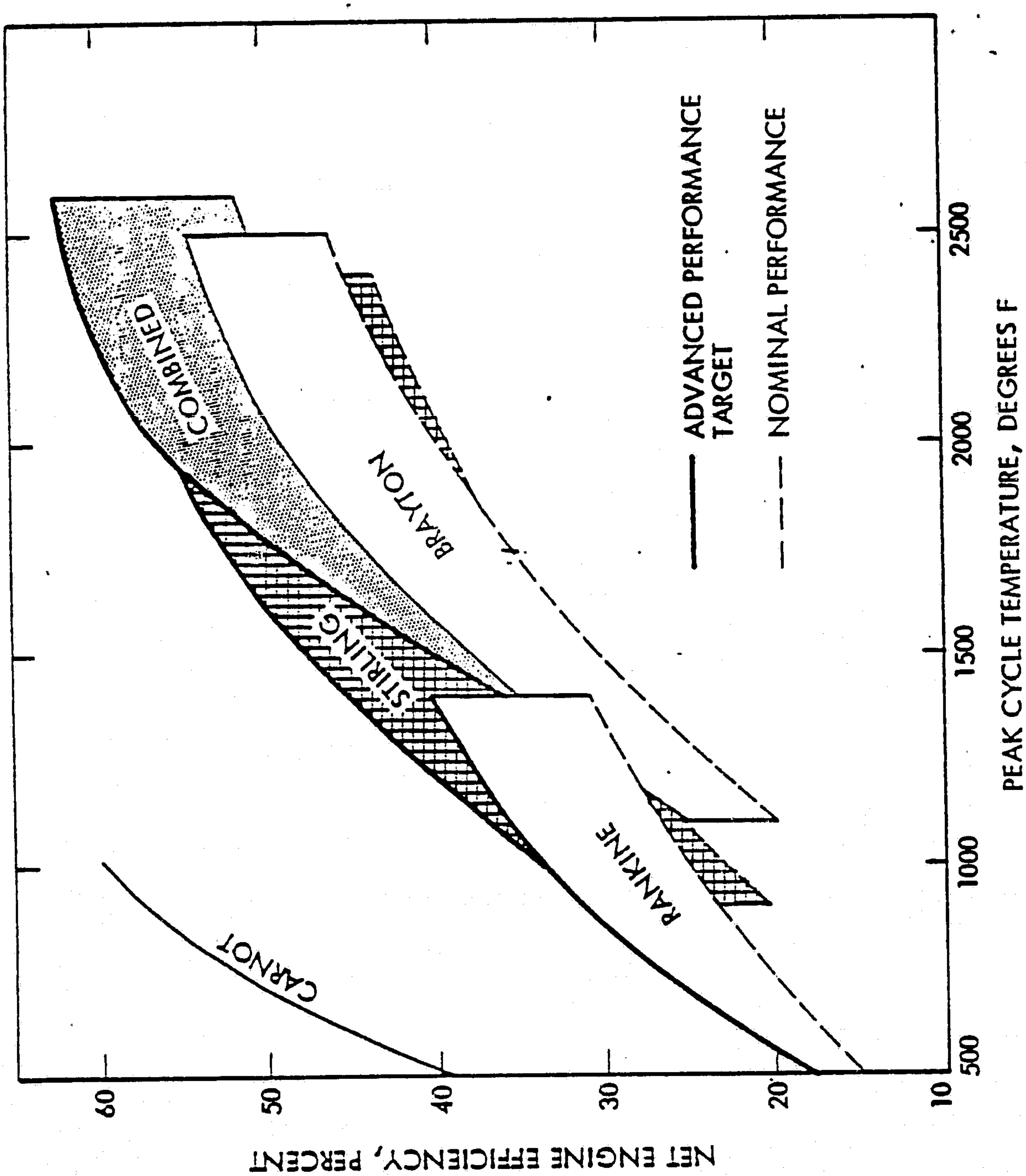

FIGURE 2-2. Comparison of Engine Efficiencies

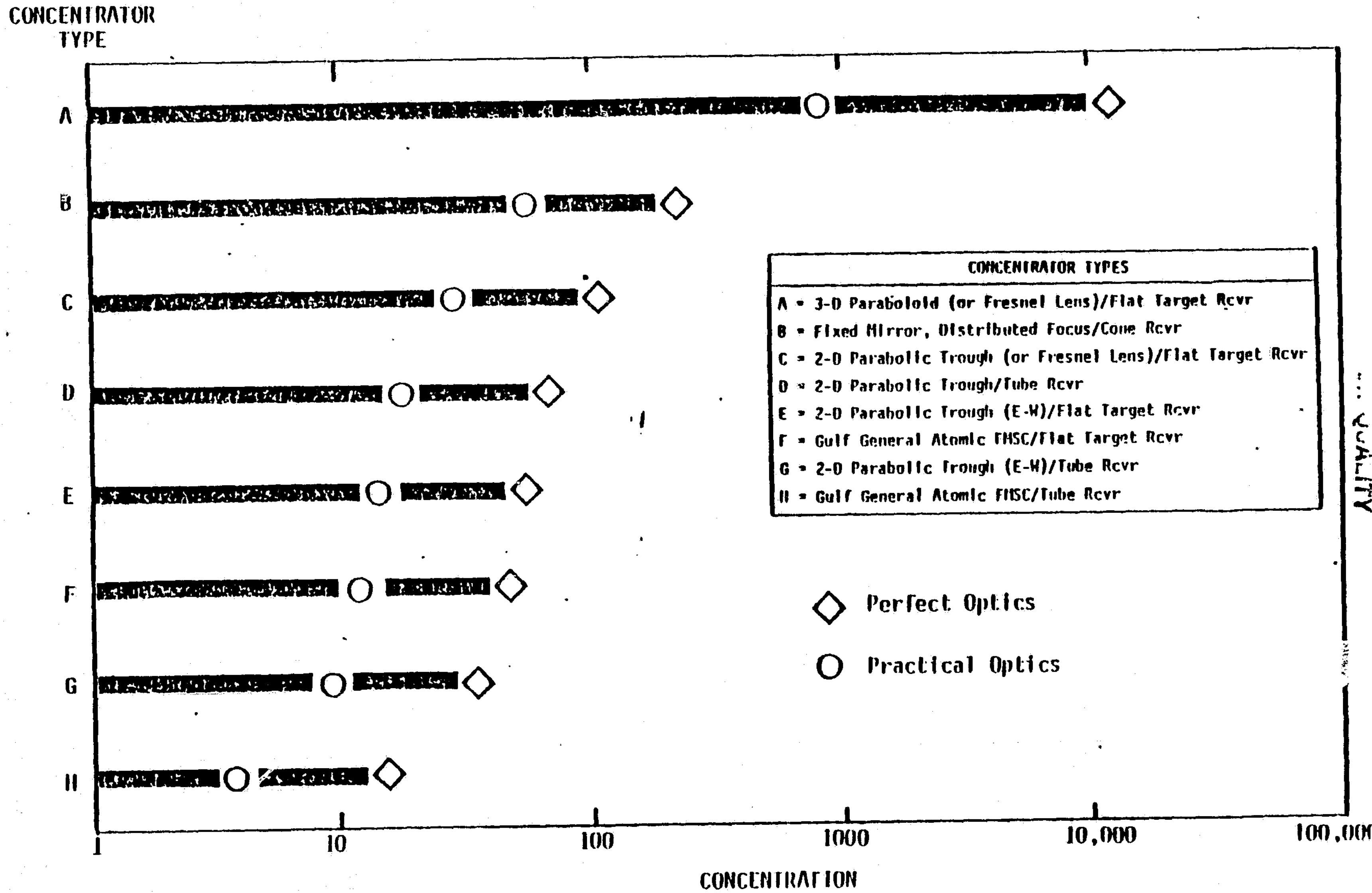

FIGURE 2-3. Comparison of Solar Concentrators

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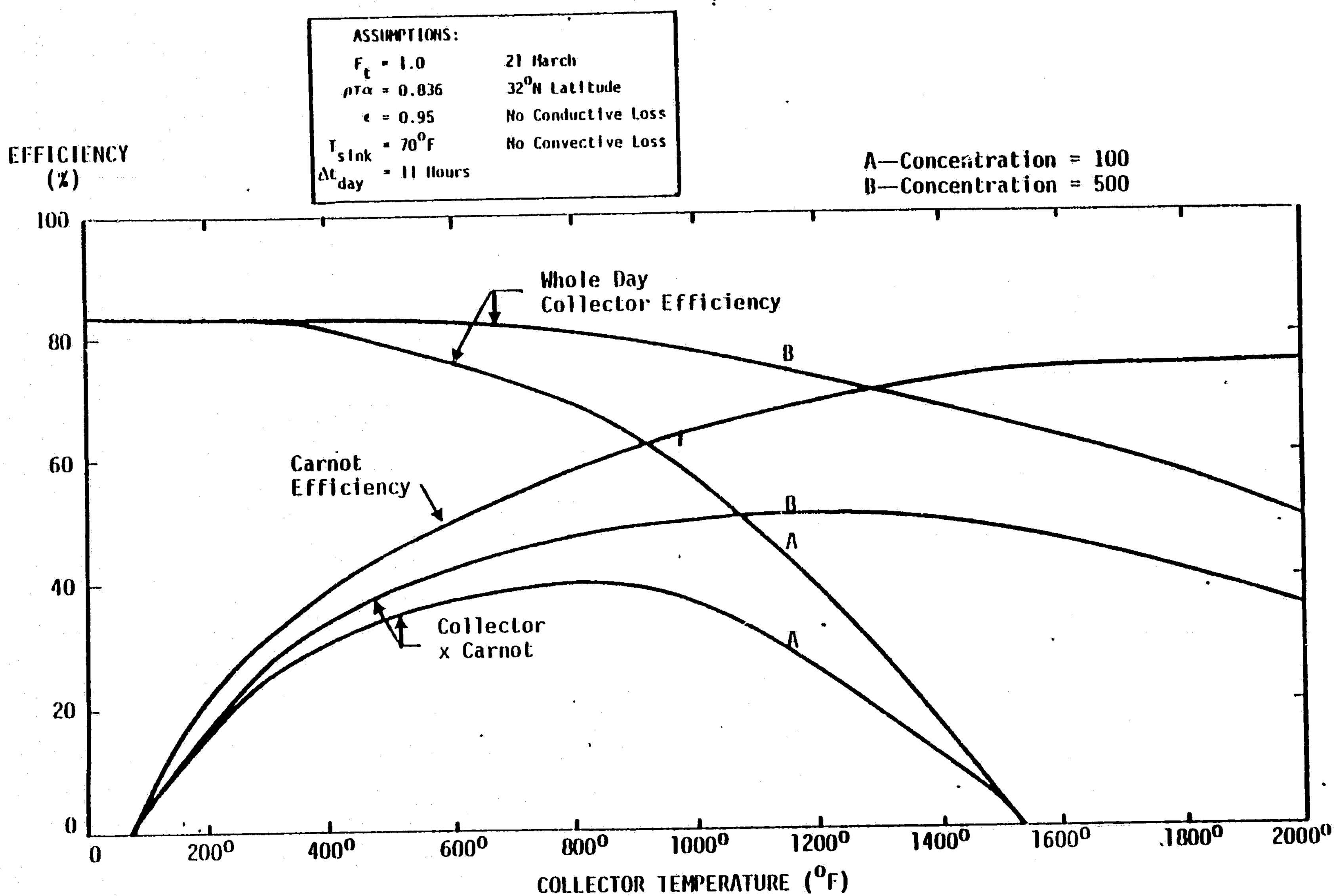

FIGURE 2-4. Collector Efficiency and Carnot Efficiency versus Operating Temperature

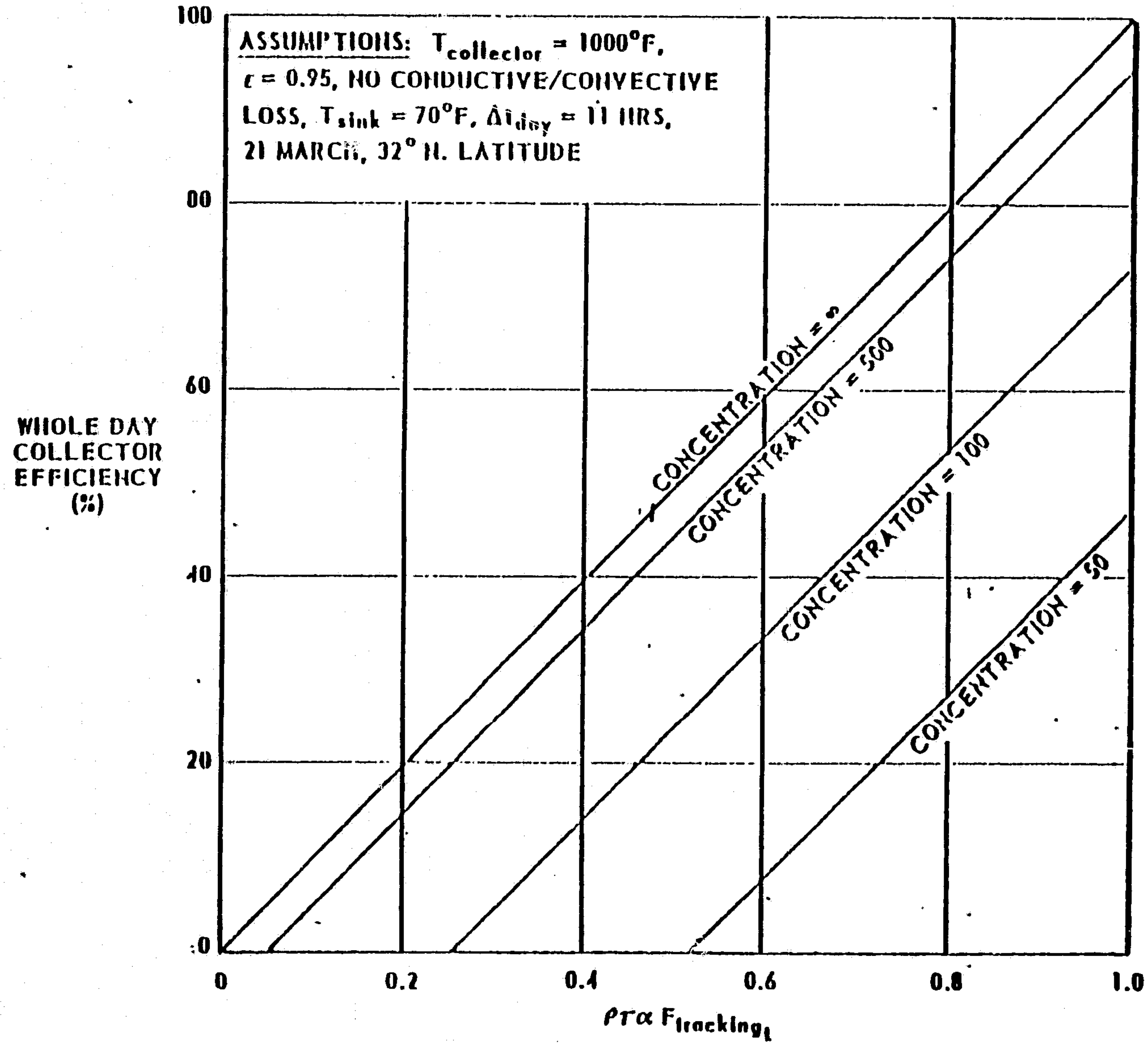

FIGURE 2-5. Collector Efficiency vs. Optical Efficiency Factor ($\rho\tau\alpha\, F_{tracking_t}$) for Various Concentrators

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that an increase in concentration level from 500 to infinity (an impossibility) results in only a six percent increase in whole day collector effieiency, but a six percent increase in optical efficiency factor yields a six percent increase in collector efficiency. The implication of the information in Figure 2-5 is that the optical efficiency factor is a dominant variable in determining collector efficiency, and thus must be maintained at a high value even at the sacrifice of small gains in concentration. The significant parameter in the optical efficiency factor is F_t, the collector tracking efficiency since significant increase over the assumed values for other quantities, i.e., ρ and α, is not likely. Thus, fully tracking collector systems such as PFDR ($F_t \simeq 1.00$), without the use of any secondary concentrators would provide the most efficient collection of solar energy and should merit the first choice until cost and application data are factored into SPS configuration selection. On this basis, the potential first choice SPS candidate configurations will be (1 x 6 x 4 x 1) or 24 followed by 40 other candidates for either mode of generation.

Storage/Hybrid Configurations

The use of storage is based on the availability of storage media and components that will be compatible with the physical, chemical, and thermo-fluid characteristics of the heat transfer fluids selected for a specific thermodynamic cycle. In this study, thermal (or chemical) and electrical storage modes were considered with four possible combinations of storage and hybrid capability.

- No Hybrid, No Storage. In this configuration, all the thermal power absorbed by the receiver is utilized immediately by the prime mover; also, there is no source of thermal power other than the receiver. This system is expected to have a low cost and a simple operation during period of slowly-changing receiver thermal power. When the receiver power is fluctuating rapidly, as in a partial cloud cover situation, the lack of storage requires either system shutdown or a complex control system. The lack of hybrid capability makes this a system with

little reliability (capacity credit to an electric utility). However, the simplicity of this configuration warrants its consideration for SPS plants particularly for peaking applications.

- Hybrid, No Storage. In this configuration, an external thermal power source is avilable. Although there is no storage system, the hybrid heat source may, as in the case of an open Brayton combustor, have sufficiently rapid response to provide the benefits of a storage system. It is possible that, although the plant has reliability, its utilitization of solar thermal power during periods of rapid insolation fluctuation may be difficult. Nevertheless, this configuration is a potential candidate for SPS systems.

- Storage, No Hybrid. Although this system configuration has no external thermal power source, and therefore little reliability, the storage system may greatly simplify the plant operation during periods of fluctuating insolation. While, in theory, a very large storage system could provide at least some reliability, the costs would be prohibitive for any system yet developed or planned. SPS plants with this configuration are amongst the potential candidates, particularly with short-term storage and primarily daytime loads.

- Storage and Hybrid. This system configuration has both an external thermal power source and the capability to store receiver power for later use. As such, it is both reliable and flexible and thus appears to be attractive for SPS configurations.

Next,one must consider the characteristics of typical working fluids for specific thermodynamic cycles, and examine whether or not they are suitable for incorporating appropriate storage subsystems into SPS configurations. Rankine cycle typically utilizes water (steam) or other high specific heat fluids to transfer thermal energy from the receiver to the thermal storage subsystem. Brayton and Stirling cycles on the other hand generally use a gaseous working fluid (air, He, hydrogen), although

heat transfer from the solar receiver may be accomplished via a gaseous or a liquid (metals, salts) medium. In principle, either thermal or electrical storage can be used with the thermodynamic cycles considered in this study except for the Rankine through storage cycle where even in concept only the thermal storage appears practical. However, it is clearly inefficient to utilize electrical storage versus thermal storage for SPS plants utilizing a simple Rankine cycle, because of the anticipated low overall efficiency of the system, high electrical storage costs and potential control and operating advantages with thermal storage. Thermal storage in conjunction with Brayton and Stirling cycles, particularly utilizing gaseous heat transfer fluids, does not appear to be feasible. For example, the Brayton high temperature receiver outlet air is not a good heat transfer medium. Any attempt to transfer the heat to another medium, and to subsequently extract that heat into working fluid gas would result in a large loss in available energy and a greatly reduced cycle efficiency. Liquid metals as a heat transfer fluid could be used to store thermal energy which can then be extracted into the working fluid. As in the previous case, not only the overall efficiency would be reduced but also, for any reasonable storage capacity, the overall storage-heat exchange component sizes could become unwieldy particularly for focal mounted receiver-storage-energy conversion PFDR systems. Thus, for PFDR-Brayton or PFDR-Stirling solar plants only electrical storage can be considered to be viable for the distributed generation mode.

As a result of the preceding discussion, the following SPS configurations can be considered as potential candidates:

- <u>Distributed Generation Mode</u>—PFDR-SPS plants with or without electrical storage and dedicated hybrid capacity will provide (1 collector*4 cycles*4 storage/hybrid configurations*1 transport configuration) or 16 configurations utilizing either Brayton, Stirling, or combined cycle.
- <u>Central Generation Mode</u>
  - Systems with Rankine, Rankine through storage cycles, and potential storage/hybrid combinations provide (4 collectors* 2 cycles*4 storage/hybrid*1 transport) or 32 configurations.

- PFDR and Heliostat/Central Receiver—SPS plants with chemical energy transport and storage, with the storage as an essential element of the system, provide (2x6x2x1) or 24 configurations. These configurations are possible since chemical storage can permit, in principle, all six thermodynamic cycles to be operative. In these cases, storage is considered as an essential element since chemical energy transport can provide a more reasonable vehicle for energy storage prior to conversion of thermal to electrical energy. However, the development of chemical heat transfer/storage technology appears to have potential only in the years beyond 1990.
- Heliostat-Central Receiver—Plants with Brayton, Stirling, and combined cycles and electrical storage result in (1x4x4x1) or 16 configurations when each combination of hybrid and electrical storage is considered as a potential candidate.

Thus, a total of 72 potential SPS configurations exist for centralized generation mode.

Component Availability

Component availability involves several considerations, namely:

- Commercial availability
- Cost data
- Performance data
- Reliability data
- Operating procedures
- Potential performance improvements
- Anticipated market impact and penetration
- System lifetime
- Engineering aspects.

Of these, "commercial availability", cost and performance characteristics are usually the most dominant ones, although at times the engineering considerations become the significant selection factor between systems. These aspects are briefly discussed below.

A criterion for selection of various SPS configurations has to be based on "commercial availability" of components and subsystems within acceptable cost and performance. It is clear that the time and dollars required to transform hardware from the experimental to the production prototype that will allow commercial production under fixed-price contracts large. Certain components, such as prime movers, in certain size ranges, may not be production models within the 1980-1985 time frame yet may represent rather attractive options for the longer range. The technology involved in the development of attractive longer range options may need the incubation period of 1980-1985 and thus should be considered within the realms of "component availability". Similarly, technology that is attractive for the near time frame may well be limited in market penetration during the years when solar thermal systems begin to significantly penetrate the market place. Such near-term technology may well be less attractive particularly if it tends to have a short life-cycle with regard to the market place.

Moreover, some systems are commercially available today (e.g., steam turbines/generators in the 1-10 MWe range), others are at a stage of development where commercialization with available vendors is clear cut (e.g., organic Rankine turbines and dish collectors), and still there are systems for which commercial production will be reached if the system performance and market penetration were sufficient (Stirling engine). This variety in selection criteria is required by the time frame (1980-2000) of this study and the variety of applications to be considered, in addition to evaluating the cost and performance parameters for viable systems. In essence, for the more advanced systems that have at present no commercial availability, their higher projected efficiencies and costs need to be considered to permit answers to the "what if" questions for such systems.

Furthermore, "commercial availability" has different meaning for different subsystems comprising an SPS configuration. For example, while certain heat engines are commercially available today in the required size range, no large scale commercial production facility exists for the solar

collector subsystem (11 m diameter aperture) to accompany the efficient heat engine within the system size range. On the basis of the technology commercially available for large communication antennas, it is anticipated that solar collector subsystems would become commercially available as the market for solar thermal power systems develops.

Consideration of engineering aspects is a complex matter since it involves, one way or the other, analysis of system and component design, performance, operation and life-time. Moreover, to permit flexibility in system selection and develop representative simulation characteristics of certain systems, performance estimates are based on composites of similar or related systems and applications..

An example of the selection process is given for the Rankine engine. Rankine engines can be reciprocating (Carter Enterprises, Foster-Miller) or turbine (Sundstrand, Barber-Nichols). While very high performance reciprocating engines have been designed, their excellent efficiency (~33%) are based on steam inlet conditions of 922 K (1200 F) at 17.2 MPa (2500 psi) and 1120 K (1550 F) at 11.8 MPa (1700 psi) which impose significant materials constraints[2].

Reciprocating engines require cylinder wall lubrication. The lubricant "contaminates" the working fluid (steam) and must be removed before reentering the boiler. This lubricant must not only perform satisfactorily at these high temperatures, but must also have long term stability and little adverse effect on the water quality. In fact, maintaining the water quality is a major task in any high temperature steam generator. If the quality deteriorates such that it has increased dissolved oxygen or solids content the steam generator will suffer increased corrosion and scaling. Also, any entrained lubricant that comes in contact with the hot metal surface in the high heat flux region of the steam generator would be degraded. The Foster-Miller engine eliminates the lubricant problem by running dry with carbon piston rings but has increased material requirements. On the other hand, the lower performance organic Rankine turbine of Sundstrand has

an efficiency of 29 percent with throttle conditions of 700 K (800 F) at 4.14 MPa (600 psi). It is considered available as it uses commercially proven components and can thus be selected for the near term Rankine engine 4-22 kWe rating. The other engines are "commercially available" in the sense that they have been "made for a price" but the engineering considerations cited above become the dominating factors on availability. Research, development and system testing are needed before the engine could be considered available. Thus, for this project the 29 percent efficient organic Rankine turbine may be selected for the near term and a 33 percent efficient unit for 1990 and beyond. Application of considerations germane to component availability is included for each subsystem in the sections on system and subsystem performance models.

2.2 SOLAR POWER PLANT PERFORMANCE AND COST MODELS

This section describes parametric models developed by SAI and Black & Veatch (B&V) to characterize the performance and cost of the various SPS configurations. An analysis of optimal plant requirements and the determination of their economic impact and application (user) interface in terms of demand characteristics and user financing structure involves complex considerations. Thus the emphasis of the modeling effort in Task 1 was not on defining a priori the relative merits of the different SPS configurations. Rather, it was on providing parametric cost and performance models for the solar power plants and their subsystems and interfaces - such that these models can be judiciously exercised to provide in a systematic manner performance and cost inputs required by the overall methodology that involves the complex interaction between solar plant configuration, application characteristics and user economic and financial methodology. The formulation of the overall methodology for solar thermal plant impact analysis and requirements definition is the subject of Task 4 currently in progress under this study program.

2.2.1 System Performance Model Overview

A computerized performance model, QAG, recently formulated by SAI and its subcontractor B&V, simulates the performance of solar thermal power plants using hourly meteorological data and system parameters as inputs. A typical solar thermal power plant consists of several subsystems and interfaces which are specified by certain significant parameters. Certain of these parameters depend directly or indirectly on the insolation and other meteorological conditions that prevail in a given location. The performance of each subsystem is specified by its efficiency which is defined as the ratio of the output energy to the input energy to the subsystem. The interface between two interacting subsystems is characterized by linking factors which generally depend on the characterisitics of the interacting subsystems. Solar power systems simulation involves interfacing the performance characteristics of the various subsystems for design as well as off-design conditions. The off-design efficiency of each subsystem is expressed as a function of the energy input to it. The product of subsystem efficiencies and linking factors define the performance of the whole power plant.

The model, an overview of which is depicted in Figure 2-6, consists of several modular subprograms:

- Collector model, including concentrator, receiver, and thermal energy transport
- Energy conversion model, including turbine (thermal to mechanical) and generator (mechanical to electric)
- Storage/hybrid models
- Energy distribution and operating strategy.

The collector subsystems which are currently modeled include: heliostat/central receiver with a cavity receiver, heliostat/central receiver with an exposed receiver, paraboloid dishes and point focusing Fresnel collectors, parabolic troughs, and fixed mirror distributed focus (FMDF). The collector model uses interpolation tables and

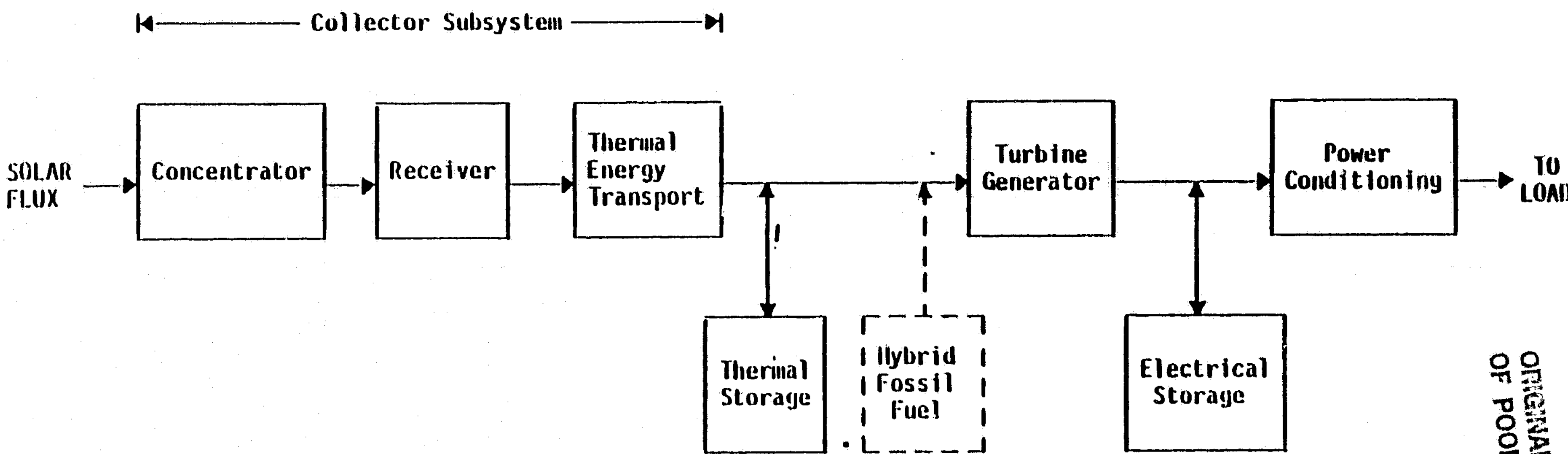

FIGURE 2-6. Generic Block Diagram of Solar Thermal Electric Generating Plant .

efficiency equations to define, as a function of hourly sun position and meteorological variables, the cosine losses, blocking and shading losses, reflectivity or transmissivity, atmospheric attenuation, tracking and surface errors, receiver intercept factor, receiver absorptivity, receiver losses due to radiation and convection, and thermal transport losses.

The energy conversion model addresses the following thermodynamic cycles: open Brayton, closed Brayton, Stirling, Rankine through storage, and combined cycles. The energy conversion model uses efficiency curves based on the best available data to model part-load efficiencies as a function of input thermal energy, ambient temperature, and pressure.

The storage subsystem includes electrical, thermal, and hybrid fossil fuel capability. Various storage/hybrid configurations are permitted and several operating strategies (level output, peak-shaving, load shifting, sun-following, etc.) can be implemented.

Since the model performs an hour-by-hour performance simulation, hourly meteorological data are required as provided on SOLMET tapes. The necessary data includes hourly values of sun elevation, sun azimuth, direct normal radiation, barometric pressure, dry bulb and wet bulb temperatures, wind speed and others. Additional inputs consist of system specification parameters associated with each plant type. Representative parameter values for the various system types have been developed based on current estimates of expected design performance.

The outputs of the model include hour-by-hour and annual totals of the plant energy distribution, including: energy from concentrator, receiver turbine generator, and total plant; energy from and to thermal or electrical storage; fossil fuel consumption for hybrid operations; and efficiencies of the various subsystems. These results can be printed if desired; more generally, however, the results are stored on file for subsequent analysis by various expansion planning and/or user load models.

2.2.2 System Cost Model

Solar power plant costs have two components: the capital cost and the operations and maintenance (O&M) cost. The capital cost is the sum of the installed cost of each subsystem and interface components. The cost of a subsystem depends on its size and the basic data are obtained from the vendors and manufacturers. The direct capital cost is multiplied by a factor which accounts for spares, contingencies, siting and indirect costs. O&M costs consist of costs associated with regular maintenance, forced maintenance and component or unit replacement or overhaul.

The system performance and cost models provide data input to the methodology for impact analysis and design requirements for various SPS plant configurations. The genesis of these models lie in the performance and cost models based on current and projected data for various subsystems comprising a SPS system. The approach and data involved in the performance and cost modeling of different subsystems are presented in the following sections.

2.2.3 Collector Subsystems

The collector subsystem model represents the energy collection system, i.e., optical concentrators, receivers, and thermal energy transport. The solar insolation received by a collector is reduced through losses at each of the subsystem units prior to its delivery as thermal energy to either the energy conversion and/or the thermal storage unit. Thus, the collector performance model begins with solar insolation per unit concentrator aperture area per unit time and ends with the thermal energy provided via a thermal energy transfer system to either or both of the two units specified above.

The collector performance model is then represented by the equation:

$$P_{TET}^{(t)} = I(t) \cdot \eta_c(t) \cdot \eta_r(Q_c, Q_{rL}) \cdot \eta_{TET}(Q_r) \tag{2}$$

where $P_{TET}^{(t)}$ is the power output of the thermal energy transport unit;

I(t) is the direct normal insolation; $\eta_c(t)$ is the optical concentrator efficiency and accounts for energy losses associated with imperfect surface reflectivity, surface and tracking errors, cosine effects, shadowing and blocking, atmospheric attenuation, fraction of operative elements, and fraction of energy effectively directed into (onto) the receiver; η_R (Q_c, Q_{RL}) represents the receiver efficiency as a function of the power input to it from the concentrator and receiver losses that include effects of reflection at the aperture, receiver surface absorption and emission factors, receiver and ambient temperatures, and wind speed. Other than reflection losses, the three principal thermal loss factors are radiation, convection and conduction. Receiver radiation losses depend on the size and apparent emmisivity of the receiver aperture, receiver temperature, view factors and emissivities of surfaces external to the receiver aperture. Convection losses are proportional to the temperature difference between the receiver and the ambient and in addition depend on the wind speed. Conduction losses through the receiver supporting structure depend on wall thermal conductivity and temperature difference across the wall $\eta_{TET}(Q_R)$ is the efficiency of the thermal energy transport system; it is a function of the amount of power being transported which determines thermal and pumping or friction losses.

Parabolic Dish/Point Focusing Fresnel Collectors

The parabolic dish concept is shown in Figure 2-7. Sunlight falling in to the dish is reflected by the mirror surface onto the aperture of a small, cavity-type receiver located at the focal plane. The receiver absorvs the hear input and delivers power to a Rankine, Brayton, or Stirling cycle engine. The overall PFDR solar power plant consists of a field of parabolic dish modules, generating power in either a central or distributed generation mode.

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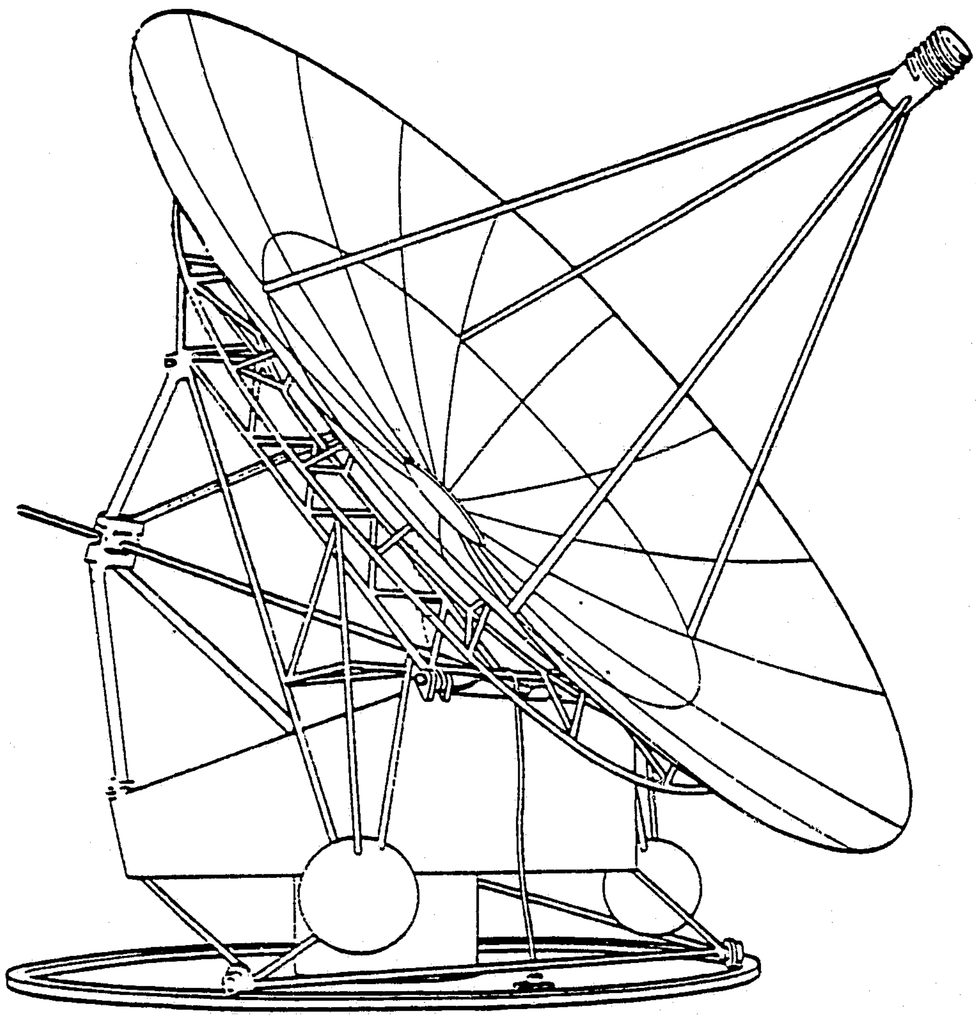

FIGURE 2-7. PARABOLIC DISH CONCENTRATING COLLECTOR

Performance Projection

The projections for design and performance improvements of the dish collector/receiver system are improved mirror reflectivity, mirror slope errors (surface waviness) and tracking errors. As described under Performance Modeling, the overall expected value of the receiver intercept is 0.95, thus little benefit would occur for present systems if the tracking errors were reduced. High peak flux is essential for effective performance of high temperature systems. Total system performance is the measure in selecting the operating temperature of a solar thermal system[3]. Thus, the receiver and thermal energy transport efficiencies and potential improvements in their values need be considered. Flux distribution at the receiver is one factor that affects its efficiency. For illustration, the receiver efficiency, shown in Figure 2-8, is determined for a circularly gaussian flux at the aperture by equation (3)[4].

$$\eta_r = 1 \mp u(\ln u - 1) \qquad (3)$$

where

$u = \phi_r/\phi_o$
$\phi_r = \varepsilon\sigma T^4$ (see definition of T below)
ϕ_o = peak value of circularly gaussian flux, $\phi_r = \phi_o \exp(-r^2/2\sigma_s^2)$
T = cavity effective temperature for receiver radiation losses
ε = emissivity
σ_s = standard deviation of flux map on aperture plane
σ = Stefan-Boltzmann constant
r = receiver radius

For high temperature systems, 1100 °K (1500 °F) or greater, assuming a cavity effective temperature of 50 °K (90 °F) above the working fluid turbine inlet temperature and an emissivity of 1.0, ϕ_r equals or exceeds 99 kW/m^2. Thus, for an 85 percent cavity efficiency ($u = 0.032$ from Figure 2-8), $\phi_o = 3094$ kW/m^2. Total power redirected from the dish

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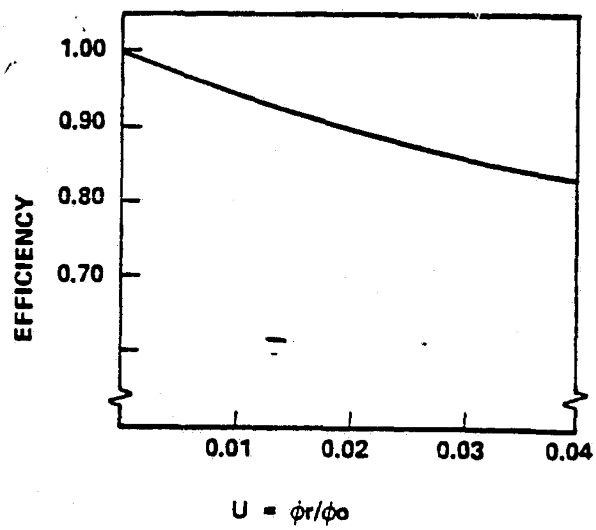


FIGURE 2-8. CAVITY EFFICIENCY

to the aperture of the receiver is $2\pi\sigma_s^2\phi_o$. For constant dish diameter, the power is constant and σ_s decreases as ϕ_o increases. The effect of increasing ϕ_o on system performance implies that the slope and tracking errors must be reduced. Else, the flux spill at the aperture will result.

Parabolic collectors with secondary reflectors result in an reduced overall optical tracking efficiency[5] and thus were not considered. Moreover, PFDR systems with energy conversion unit mounted at points of the dish structure other than at the focal point were excluded since it is not clear whether the anticipated resulting increase in dish structural efficiency can offset the reduced thermal efficiency and potentially increased cost of the collector system.

In view of a large number of factors related to the concentrator structure and its optics, receiver performance parameters and designs and the energy transport system configurations for transfering thermal energy to the conversion unit, any detailed trade-off analysis of these factors is beyond the scope of this project. Thus no projections of PFDR collector performance beyond present designs or improvements in reflectivity are considered.

Component Availability

There is no commercial production of parabolic dish collector/receiver systems. Prior work requiring similar technology, such as solar furnaces, microwave antennas etc., has provided a baseline for design and confidence that such units can be built. There are numerous firms providing developmental units in the size range of 5 to 11 meter diameter aperture.

Performance Modeling

Power reflected into the receiver aperture depends upon the surface reflectance, the effective dish area illuminated by the incident solar radiation and the receiver aperture intercept factor. The total power incident on the mirror is:

$$P_R(t) = \rho \cdot I(t)(\pi/4)(D_d^2 - D_r^2)(1 - F_{sh}) \quad (4)$$

where ρ is the mirror surface reflectance; D_d and D_r are, respectively, the dish and receiver aperture diameters. F_{sh} is the fraction of energy lost due to shading of a dish by other dishes surrounding the shaded dish. Two methods are available in the literature(6,7) for computation of flux distribution and the receiver intercept factor. One method utilizes cone optics methodology(6) while the other uses ray tracing and Monte-Carlo analytic methods(7). The two methods provide equivalent results although the method of Reference (6) can potentially provide a closed form solution with appropriate simplifications. Methodology outlined in Reference (7) is used here since it has been more commonly utilized for heliostat-central receiver configurations. The receiver intercept factor, J, for reflected power having a circular gaussian distribution at the receiver aperture plane located at the dish focal point is given by equation (5)(7).

$$J = \int_0^r (Z/\sigma_s^2) \cdot \exp\left(-Z^2 + \delta^2) /2\sigma_s^2\right) \cdot B_o (Z\delta/\sigma_s^2) \, dz \quad (5)*$$

where δ = Pointing error of the dish projected onto the aperture plane

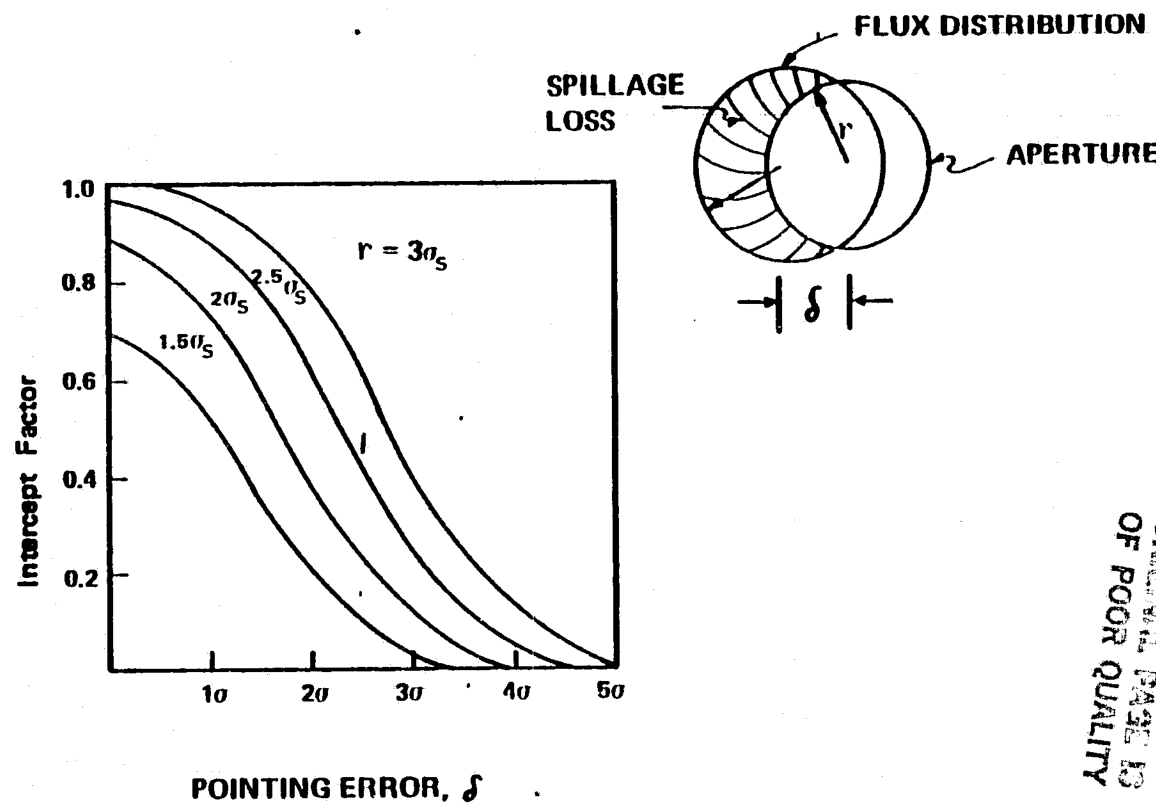
σ_s = Standard deviation of a gaussian flux distribution

B_o = Modified Bessell Function of order zero

The intercept factor is shown graphically in Figure 2-9, as a function of the aperture radius and pointing error. The aperture radius has been taken as 2.5 times the standard deviation of the redirected flux since it gives a higher receiver efficiency than the smaller apertures ($1.9\sigma_s$) often cited in the literature(7).

The receiver performance is computed by equating the power entering the aperture to the power absorbed by the cavity plus the power lost through reflection, conduction, convection and thermal radiation.

* Non-gaussian flux distributions at the receiver aperture plane will be considered during sensitivity analyses to be conducted under Tasks 4 through 8.



(σ_S IS STD. DEV. OF FLUX DIST.)

FIGURE 2-9. DISH COLLECTOR INTERCEPT FACTOR

Thus

$$P_{IN} = P_R(t) \cdot J(t) \tag{6}$$

The power absorbed in the receiver is thus given by:

$$P_{ABS} = \alpha P_{IN}(1-F_{rf})(1-F_{cv})(1-F_{cn}) - P_{RR} \tag{7}$$

where α is the effective receiver surface absorptivity; F_{rf}, F_{cv}, and F_{cn} represent respectively the fraction of power lost through reflection, convection and conduction; and P_{RR} is the thermal radiation loss.

The thermal radiation loss is computed using an effective blackbody cavity temperature which depends on heat balance and is a function of the aperture input power. The quantity P_{RR} is given by Equation (8).

$$P_{RR} = \sigma\varepsilon A_r(T_r^4 - T_o^4) \tag{8}$$

where σ is the Stefan-Boltzman constant; ε is the effective receiver surface emissivity; A_r is the receiver aperture area; and T_r and T_o represent, respectively, the effective cavity blackbody and ambient temperatures.

The electric generating capacity of an SPS plant is a function of the dish size, the number of dish modules and the geometric configuration and inter-module spacing of the field of dishes. In addition, losses associated with mode of energy transport must be included to estimate the effective capacity of the plant.

The spacial arrangement of the dish collectors affect their energy collection efficiency, the thermal or electrical losses associated with field interconnections, the installation cost, and the land (space) requirements. While some trade-off analyses have been performed of spacing between dishes, the conclusions reached present neither the best nor optimal design criteria. For example, in the Shenandoah Large-Scale Experiment studies[7a], the driving criterion was maximizing the total energy collected by the receiver/dishes in the field space available and not cost/effectiveness nor minimal life cycle cost-of-electricity. The field arrangement has a high ground

cover ratio, 0.47. The annual shadowing losses, computed by Sandia using weather tape data for Shenandoah, were 15 to 17 percent which represents a significant loss in collected energy.

In this study, the parabolic dish size is fixed at 11 m diameter aperture. While the number of fixed aperture dish modules provide a first measure of the plant capacity, a more precise estimate requires the analysis of shading losses for different parabolic dish field configurations. An analytic method and a computer program have been developed by SAI for computing energy losses due to shading of a row of parabolic dishes by the row ahead of it. Two field configurations, namely hexagonal and square, were evaluated. B&V conducted an independent, simplified analysis of the shading losses, F_{sh}, for the latter field configuration and confirmed the results obtained by SAI. A conclusion of these analyses is that the annual average shading efficiency is largely a function of the ground cover ratio and is nearly independent of the detailed field arrangement. The methodology used and the results obtained to date are described below.

Consider two tracking circular dishes of unit radius in a horizontal plane. Construct a set of cartesian coordinates with one dish at the origin and the other at x,y, (x and y in dish radii). The shadow cast by the center of the shading dish (arbitrarily selected as the one at the origin) will intersect the plane of the other dish at a point, determined by the azimuth and elevation of the sun. To begin with, analytical equations are developed to determine the shading of one dish by another for any latitude or day of the year. To do this, two assumptions were made for simplification.

- First, the sun is treated as a point source at an infinite distance. The omission of the penumbra effect has little impact on accuracy when the collector spacing is small. Further, the penumbra effect is largely self-cancelling. The magnitude of parallax is negligable.

- Atmospheric refraction is not accounted for. However, the sun is considered available only when its elevation exceeds or equals 5^{o}, and refraction at that altitude is only 10' of arc.

The collectors are normalized to unit radius and separated by a distrance n (in dish radii) along a bearing (Γ) measured from north. For the latitude, L, and solar declination, (dec), a value of the hour angle for which the solar elevation is 5^o is determined. This value, ξ_o, is given by:

$$\xi_o = \text{Integer Value} \left[\left(\cos^{-1} \frac{\sin 5^o - \sin(\text{dec}) \sin L}{\cos(\text{dec}) \cos L} \right) + 0.5 \right]$$

A simple computer program computes the portion of the shaded dish for 4 minute increments and from $-\xi_o$ to $+\xi_s$. The projection of the shadow of the shading dish onto the plane of the shaded dish is compared, and the distance, s, from the centers of the shadow and shaded dish is:

$$s = n \left(\sin^2 \delta_s + \cos^2 \delta_s \sin^2 H \right)^{1/2}$$

where H is the solar elevation and δ_s equals $(\Gamma - Z_n)$; and Z_n is the sun's azimuth measured from north.

H and Z_n are computed using standard equations:

$$\sin H = \sin(\text{dec}) \sin L + \cos(\text{dec}) \cos L \cos \xi$$

$$\cos Z_n = \frac{\sin(\text{dec}) - \sin L \sin H}{\cos L \cos H}$$

where ξ is the time increment in degrees.

$$Z_n = Z, \text{ if } \xi \leq o$$
$$= (360^o - Z), \ \xi > o.$$

If $s \geq 2$, no shading occurs. For $o \leq s \leq 2$, the shaded area is β_A which is given by:

$$\beta_A = (2\theta - \sin\theta \cos\theta)$$

where

$$\theta = \cos^{-1} (s/2) \text{ for } o \leq s \leq 2.$$

The values of β_A and the resulting shaded area fractions are computed for each increment of ξ.

Figure 2-10 shows a plot for the blockage of one dish by the other dish. The latitude is 35°N, and the density (dish area to ground area) is approximately 0.4.

The next step is to consider a field of parabolic dishes. Field configurations considered included: hexagonal, hexagonal rotated through 30° and square (trapezoidal). A computer program was used to estimate annual energy loss due to shading as a function of the ground cover ratio. The results are shown in Figure 2-11 for all three field configurations.

The procedure and assumptions used in shadow loss estimation are outlined below:

Only the first half of the solar year, December 21 through June 21 was used; symmetry accounted for the second half. The first half of the year was divided into three two-month intervals. The midpoints of those three intervals were used in the analysis, e.g., January 21, March 21, and May 21. For each of those three days, only the solar morning was analyzed; symmetry accounted for the afternoon. The mornings were divided into six one-hour intervals and the midpoints of those intervals were used for the analyses, e.g., 0630, 0730, 0830, 0930, 1030, and 1130. ASHRAE clear air insolation model with summer and winter clearness factors of one was used. The shadow calculation was performed using Boolean algebra. Each dish is modeled as a 21 x 21 array of 1's and 0's; the 1's corresponded to the mirror surface. The array of dishes on the ground was modeled as a 7 x 7 rhomboidal array. Therefore, 48 near neighbors are included as potential shadowers. While these are not necessarily the 48 <u>nearest</u> neighbors, they come very close for all practical cases. The analytic methodology used in the shadowing calculation is as follows.

- A set of 48 position vectors is developed. These are the displacements of the 48 near neighbors from the base collector.
- For the time point in question, a unit vector to the sun is generated.

The dot products between that unit vector and the 48 position vectors

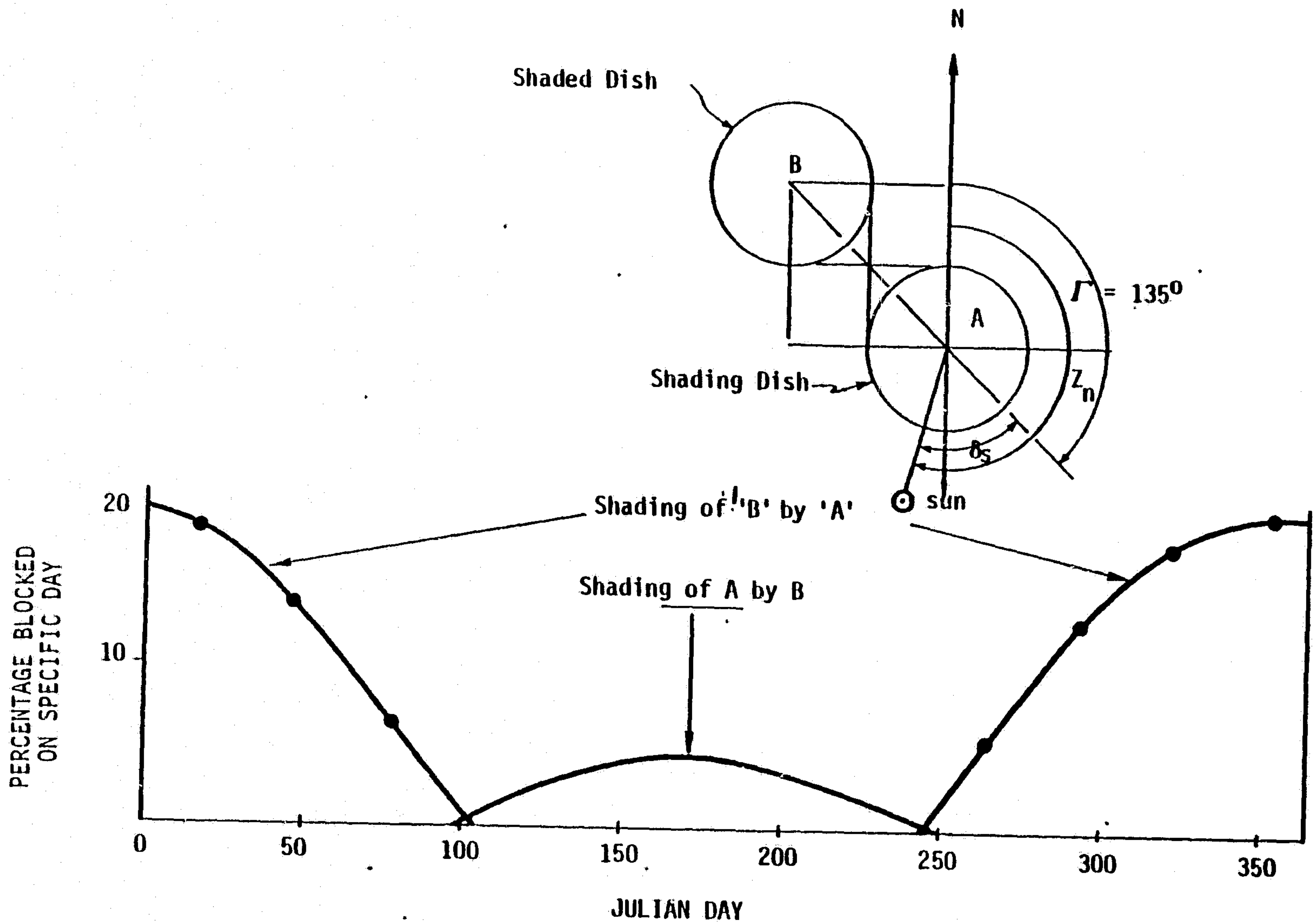


FIGURE 2-10. Blockage of Dish B by Dish A

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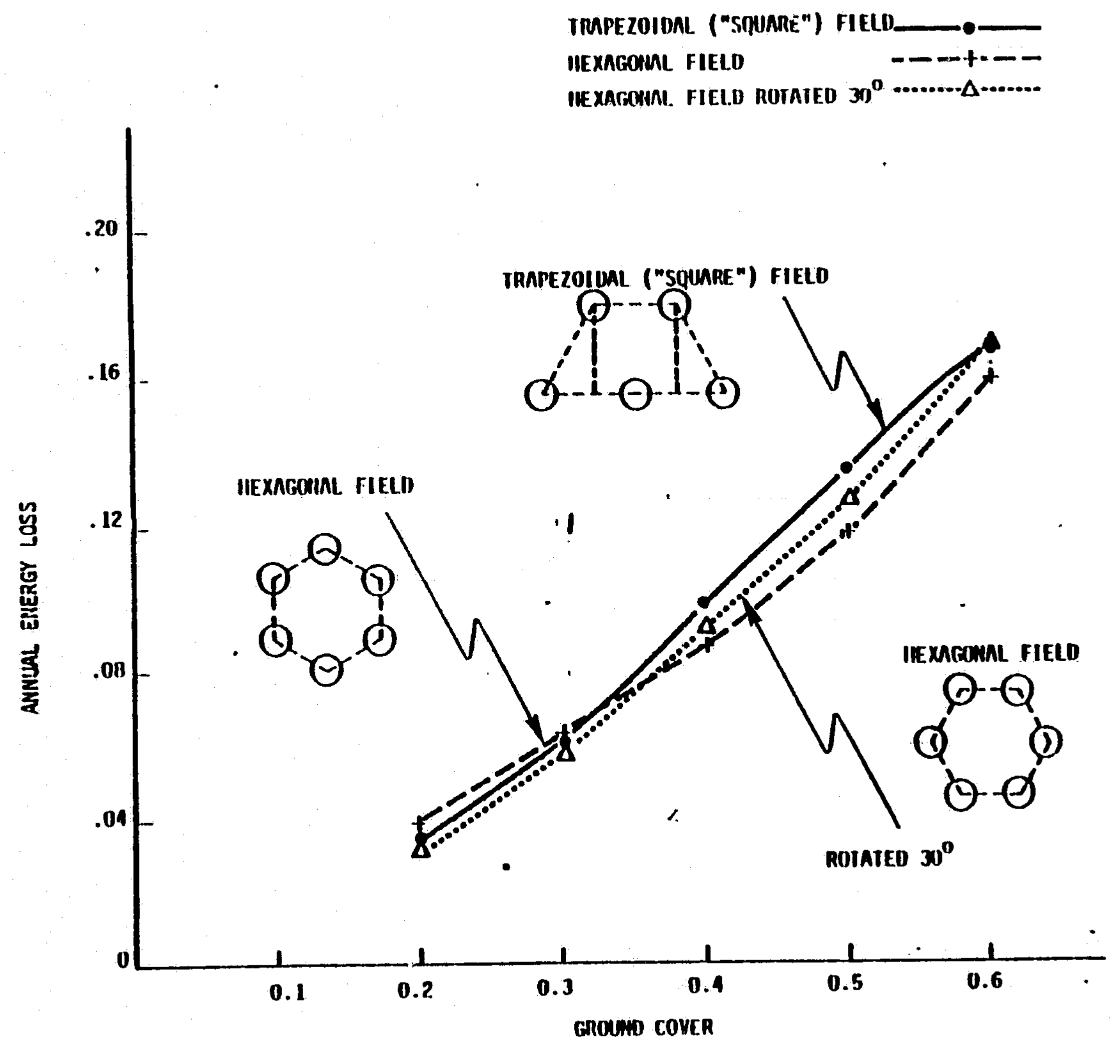

FIGURE 2-11. Energy Loss versus Fractional Ground Cover Ratio for a Field of Parabolic Dishes

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are calculated. All collectors with non-positive dot products are rejected for further calculations at this time point. For the remaining collectors, the magnitude of the projection of their position vectors onto the plane of the base collector is calculated. All collectors with magnitudes greater than the collector diameter are rejected. Next, for the remining collectors, their binary matrices are overlaid and Boolean algebra used to determine the shadowed area.

B&V utilized its solar optics computer program to develop a simplified shading model which was applied to a configuration of parabolic dishes arranged in a diamond pattern with different E-W and N-S spacings. Calculations were performed for a site at 39°N latitude and with a clear air insolation model. The results, shown in Figure 2-11(A), can be represented by the equation:

$$(1-F_{sh}) = 1.0 - 0.19(GCR) - 0.28(GCR)^2$$

where (GCR) is the ground cover ratio.

Optimization of dish field layouts has not been studied to the extent that central receiver fields have been studied and variations of the thermal power incident on the collectors throughout the diurnal cycle is more sensitive to the sun's position for a dish field than it is for a heliostat field. The increased sensitivity to the sun's position is associated with the uniform field array used for the dishes compared to a variable array orientation and variable ground cover ratio used for the heliostat field. Figure 2-11B shows the sensitivity of shading efficiency to the sun's position (azimuth and elevation) for the Shenandoah field layout.

Although the methodology, illustrated here, is an approximate one, it does provide an adequate approach to the modeling of shading effects to be accounted for in the SPS impact analysis and requirements definition activities. Moreover, this approach can be used to calculate shadowing losses for any regular dish array pattern. The effects of the deviation from a regular geometric field configuration and the site specific

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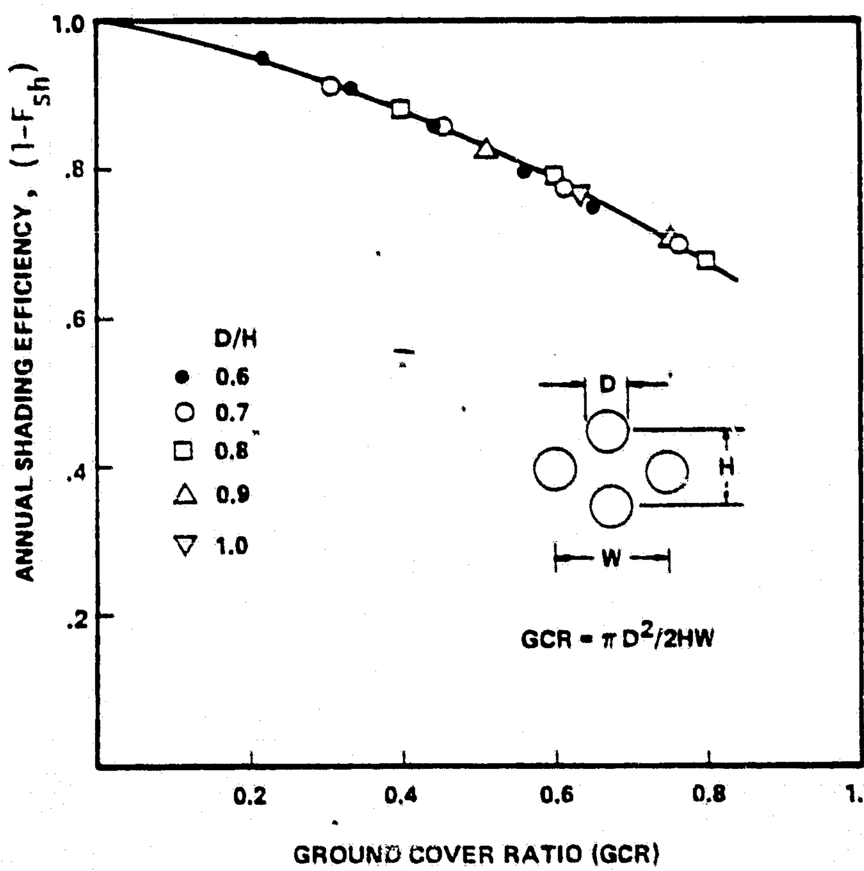

FIGURE 2-11A. ANNUAL AVERAGE SHADING EFFICIENCY FOR DISH COLLECTORS

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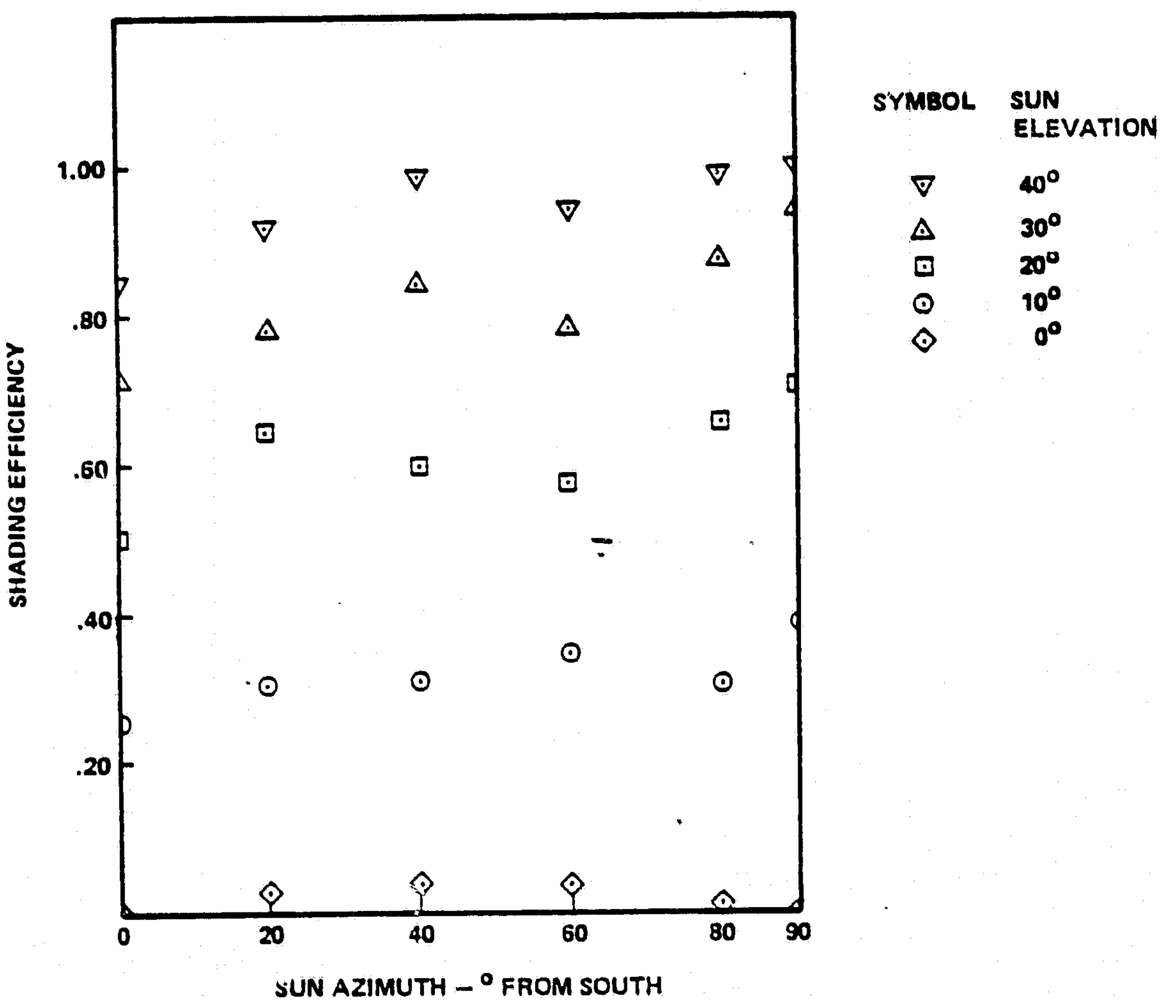


FIGURE 2-11B. SHADING EFFICIENCY VS. SUN POSITION

DISH ARRANGEMENT IS E-W DIAMOND PATTERN
N-S SEPARATION = 1.27 DISH DIAMETERS
E-W SEPARATION = 2.63 DISH DIAMETERS

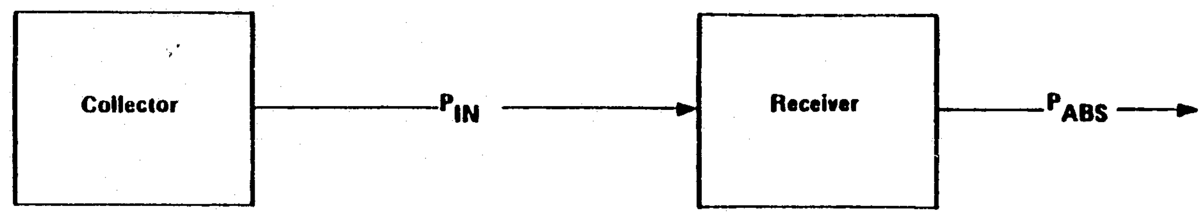
insolation data are being examined. The overall shadow loss program is being incorporated into the collector performance computer program. The shadow loss factor evaluated for the time point for which collector performance is desired enters into the performance model as a multiplicative parameter.

The input and output requirements for the PFDR collector are given in Figure 2-12. The outage value for the PFDR system collector is assumed to equal this parameter for the heliostats which is reported to be 3.2 percent for the Barstow heliostat collector field[8].

Cost Projections

The principal elements of cost for the PFDR collector are the parabolic dish cost, the receiver cost, and the energy transport system cost. The collector cost per unit aperture depends on the manufacturer's specific design, the unit production size, and the parabolic dish size. Table 2-1 shows available estimates of concentrator and receiver costs, along with the unit production rate and dish aperture diameter where available. Collector costs are seen to decrease as unit production rates increase. Moreover, cost per unit aperture area as a function of increasing aperture diameter first decreases, achieves a minimum, and then begins to increase. McDonnell-Douglas[8,11] estimates that the concentrator cost is minimum for a dish diameter of about 8 meters while Ford Aerospace estimates indicate a cost minimum at around 11 meters in diameter. In-house studies at SAI as well as data available from E-Systems, Inc.[9], suggest that concentrator costs will be minimum at around 11 meter aperture diameter for parabolic concentrators.

O&M costs are estimated at 27.7 mills/kWh for the distributed generation mode and 23.7 mills/kWh if steam is collected to a central unit (central generation)[10].



Collector Inputs	Receiver Inputs
Dish Diameter	Aperture Radius
Receiver Diameter	Per Cent Reflection Loss
Focal Length	Per Cent Convection Loss
Mirror Reflectivity	Per Cent Conduction Loss
Tracking Error	Surface Emissivity
Standard Deviation of Flux Distribution	Working Fluid Temperature
Number of Dish Modules	
Insolation	

FIGURE 2-12. DISH COLLECTOR BLOCK DIAGRAM

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TABLE 2-1. Available Cost Data on Point-Focusing Parabolic Collectors

REFERENCE	(11)	(11)	(11)	(11)	(11)	(11)	(12)	(13)	(13)	(7)	(7)	(14)	(20)
MANUFACTURER	FORD	FORD	MCDONNELL DOUGLAS	MCDONNELL DOUGLAS	-	-	-	-	-	-	-	-	-
UNIT PRODUCTION SIZE (UNITS/YEAR)	5,000	25,000	25,000	25,000	1,000	25,000	-	-	-	1	200	-	-
DISH DIAMETER (METERS)	11	11	8	11	-	-	-	11	11	-	-	-	8
YEAR $	1978	1978	1978	1978	1978	1978	1975	1975	1975	-	-	-	-
COLLECTOR COST (CONCENTRATOR + RCVR)($/$m^2$)							62-190						
CONCENTRATOR COST ($/$m^2$)	106	~80	77	85	-	-	-	182	182	172	75	120	80
RECEIVER COST ($/$m^2$)	-	-	-	-	26	20	-	7.6(1)	11.5(2)	-	-	-	7.2

(1) DISH-STEAM
(2) DISH-STIRLING OR BRAYTON

Heliostat/Central Receiver Collector

Optimization studies of central systems have shown that for optimum performance the field configuration is dependent on the receiver working temperature. For high temperature systems, 1100°K (1500°F) and above, a cavity receiver driven by a north field is best[15], for moderately high temperature, 800°K (1000°F) or less, an exposed or external cavity with a surrounding (360°) heliostat field is best[16]. In both cases, the plan shape of the field is an oval. Furthermore, the field shape does not change rapidly with system thermal power rating, thus allowing size scaling. The exact details of the shape and heliostat deployment procedure are dependent on numerous site specific variables. Alternate field choices differ in performance by only a few percent.

For the impact analysis and requirements definition study, the evaluation of candidate systems should be made with a good representation of the systems to be installed at the site. The fields for the two cases cited above satisfy this requirement. Each is optimized for a design timepoint and represents the collector field performance for its temperature range.

Performance Projection

Projections of performance improvements include mirror reflectivity, mirror surface waviness, and heliostat tracking accuracy. The present techniques of reflective surface fabrication give a spectral reflectivity of 0.92 when the mirror is clean. Allowing for degradation due to dirt and dust, an average reflectivity of 0.88 has been chosen as the default value. Other choices can be modeled by inserting the desired reflectivity into the program. Changes in slope and track error are not expected to occur because present manufacturing techniques provide the level of precision used as, so to speak, a by-product. Cost reductions associated with reduced performance has been a moot question.

Component Availability

The main elements of the central-receiver collector system are the heliostats and the receiver tower unit. Their availability is related to the DOE program on central receiver solar thermal systems. Present plans and action of DOE indicate that the heliostats and receiving will be available in the 1985-2000 time frame. Further, it appears that there will be multiple vendors which is an aid in maintaining benefit from cost competition.

Performance Modeling

The performance of either heliostat field can be described by one equation. The power redirected to the receiver surface P_{IN}, is

$$P_{IN} = A_M \cdot R \cdot F_0 \cdot I \cdot F_{COS} \cdot F_{SB} \cdot J \cdot F_{SP} \cdot F_{TS} \cdot F_{AT} \cdot F_W \quad (17)$$

where the various parameters represent: A_M - Total field mirror area; R - Mirror reflectivity; F_0 - Fraction of heliostats operating; I - Direct normal insolation; F_{COS} - Field cosine factor; F_{SB} - Field shadow/block factor; J - Receiver intercpet factor; F_{SP} - Sensor post shadowing/blocking factor; F_{TS} - Tower shadowing factor; F_{AT} - Atmospheric transmission factor; and F_W - Wind speed factor. Mirror area is the controlling factor in fixing the plant generating capacity. All linear dimensions of the collector/receiver system are assumed to scale with the square root of the mirror area. The consequence of this scaling method is that cosine, shadow/block, and receiver intercept factors remain independent of plant scale. This assumption is strictly true only if heliostat size scales with plant size, but the error introduced by maintaining a fixed heliostat size is very small in the 1 to 10 MWe range.

Since cosine, shadow/block, and receiver intercept factors are dependent on sun position, they are combined into a single factor, termed the collector efficiency. Figures 2-13 and 2-14 display the collector efficiencies as a function of sun position for both the 360° field and the north field.

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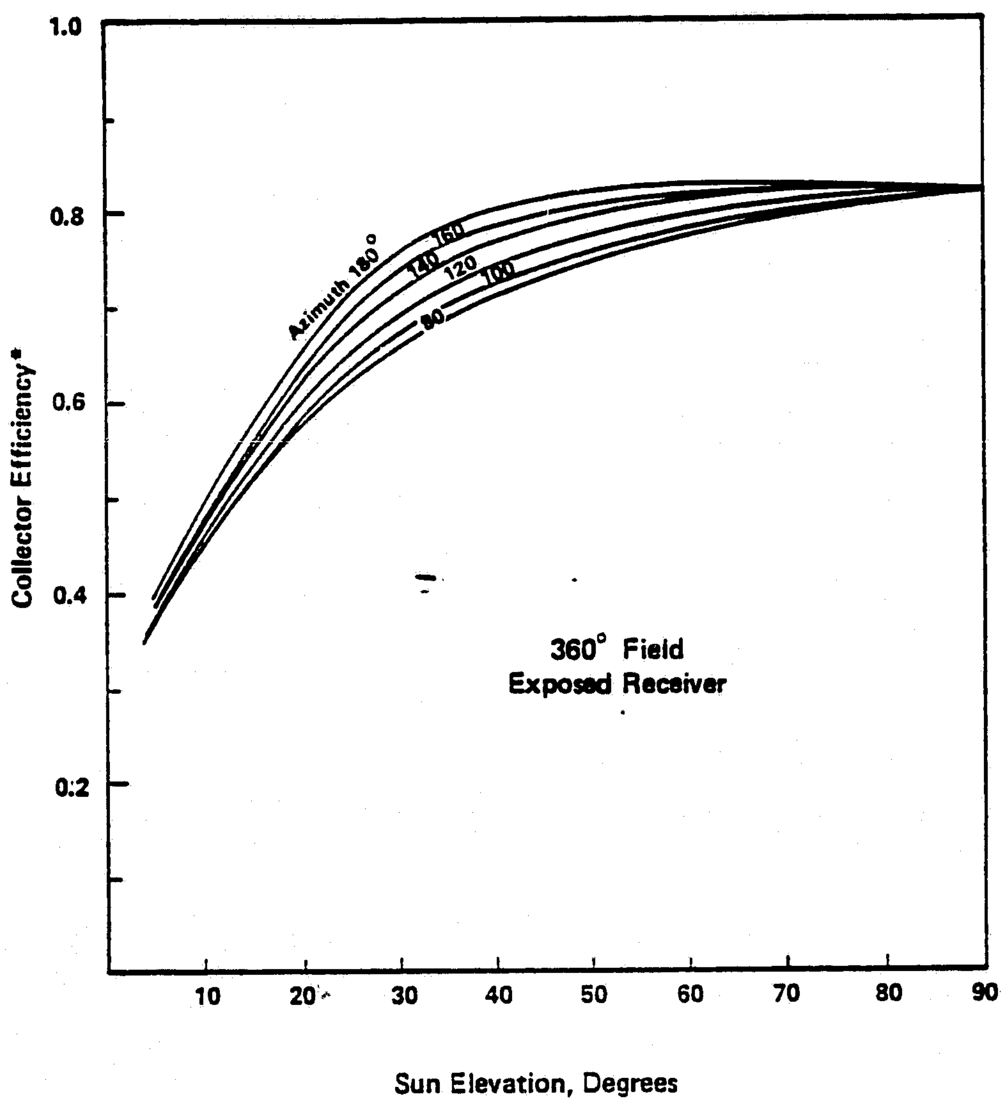

FIGURE 2-13 CENTRAL RECEIVER COLLECTOR EFFICIENCY

*Includes cosine, shadow/block, and receiver intercept factors.

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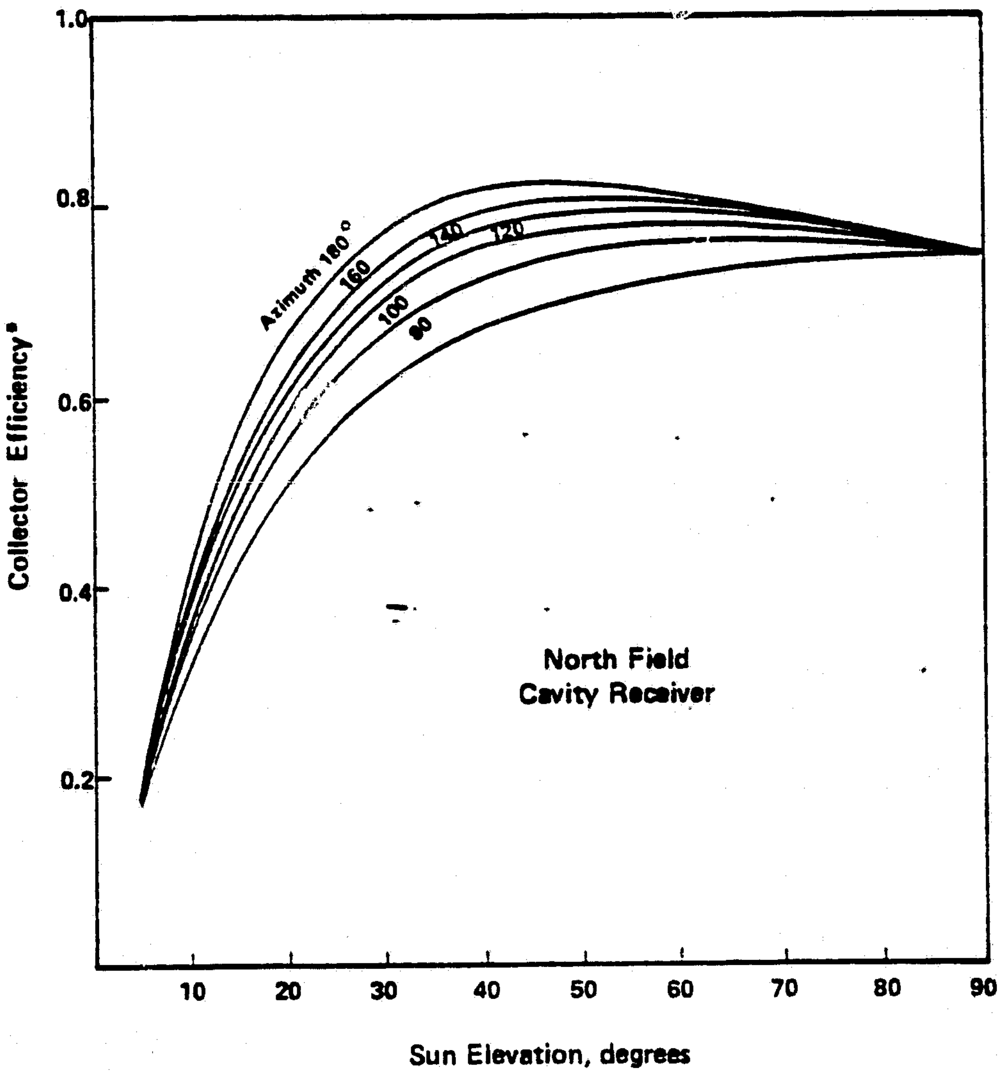

FIGURE 2-14. CENTRAL RECEIVER COLLECTOR EFFICIENCY

*Includes cosine, shadow/block, and receiver intercept factors.

The suggested value for heliostat outage is 3.2 percent as reported by McDonnell-Douglas in the Barstow Pilot Plant preliminary review[8]. The suggested value for mirror reflectivity is 88 percent, which is an average unwashed value.

The atmospheric transmission factor is the only term in the collector model which is dependent on plant scale. Figure 2-15 shows a comparison of the transmission factors for the 360° field and the north field as a function of mirror area. The attenuation model used to compute F_{AT} was used by MDAC and the University of Houston[8].

The receiver performance for both the exposed and cavity type receivers is computed in a manner similar to that used for point-focusing parabolic dish collectors. As previously, the reflection (at the receiver aperture), conduction and convection loss factors are user inputs, and default values are provided for the various receiver designs and operating conditions.

The block diagram, Figure 2-16, shows the input options available in the central-receiver model. Wind speed is included as a user input but only affects shut-down of the plant operation when a wind speed maximum value is exceeded.

Cost Projections

There are three major elements to a central receiver collection subsystem: The heliostat field, the receiver and the tower. The heliostat field capital cost has received considerable attention[17,18,19] and it appears that the DOE goal of $\$64/m^2$ in 1975 dollars or $\$97/m^2$ in 1980 dollars is realizable. Assuming a 7 percent annual escalation factor from 1975 through 1979 the DOE cost goals translate to $\$75/m^2$ (1979 dollars) for heliostat-receiver collectors with mirror reflectivity of 0.88. The indicated cost includes installation, foundation, field wiring and control system. The tower cost based on a steel space frame structure has been estimated by Black & Veatch and the relationship between tower height and cost is shown in Figure 2-17. This tower is for a "representative site" and the cost estimates agree with other DOE studies[20]. The receiver

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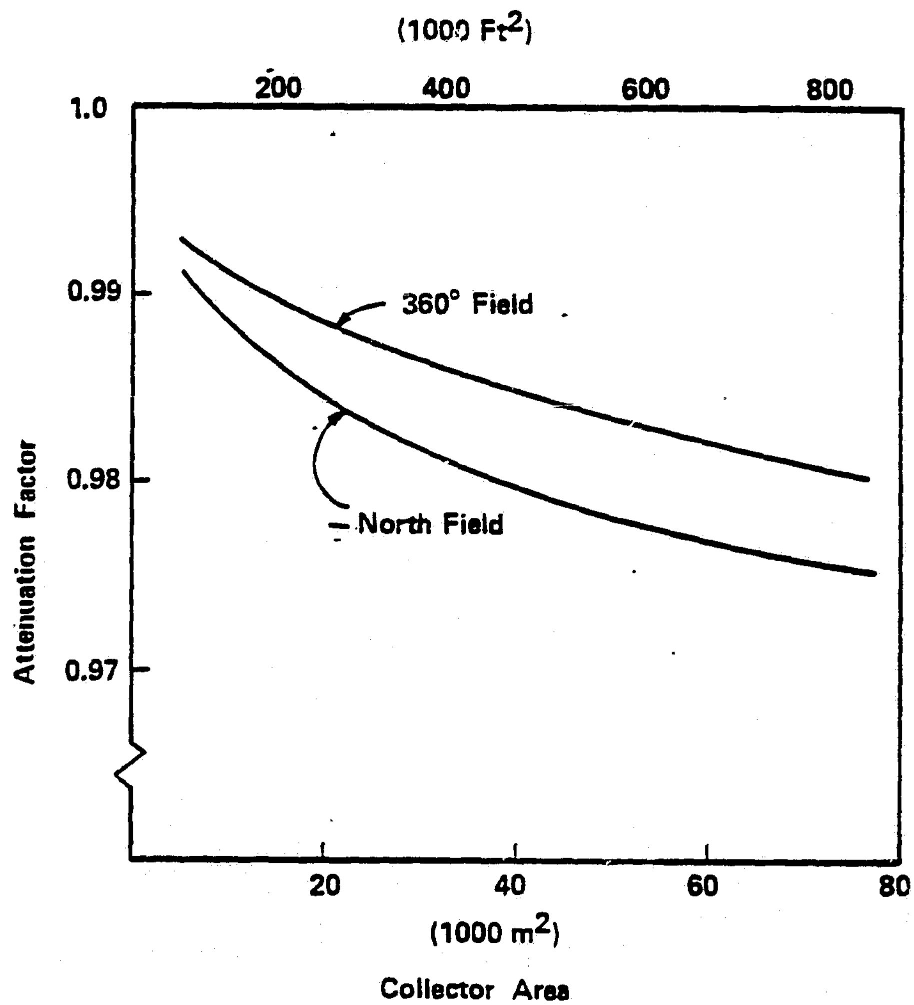
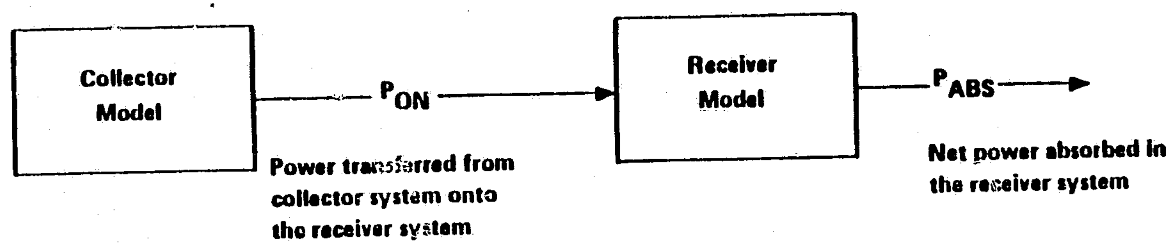


FIGURE 2-15. CENTRAL RECEIVER ATTENUATION FACTOR



Collector Inputs

Collector Area
Insolation
Sun Azimuth, Elevation
Wind Speed
Maximum Wind Speed Allowable
Mirror Reflectivity

Receiver Inputs

Reflection Loss Factor
Convection Loss Factor
Conduction Loss Factor
Surface Emissivity (used to calculate [illegible] loss)
Working Fluid Temperature

FIGURE 2-16. Central Receiver Computer Model Block Diagram

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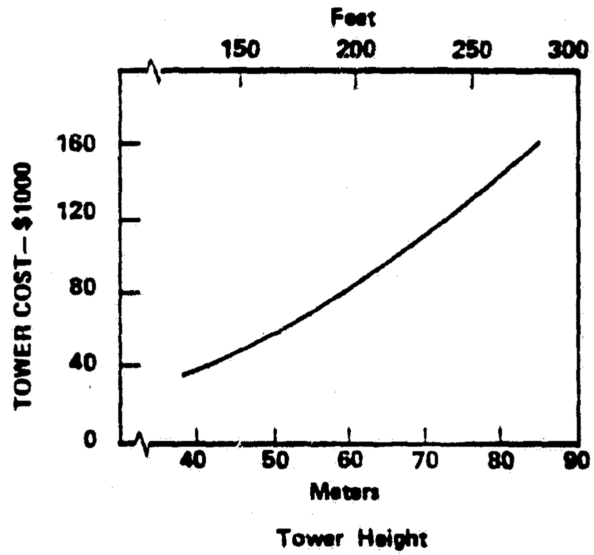
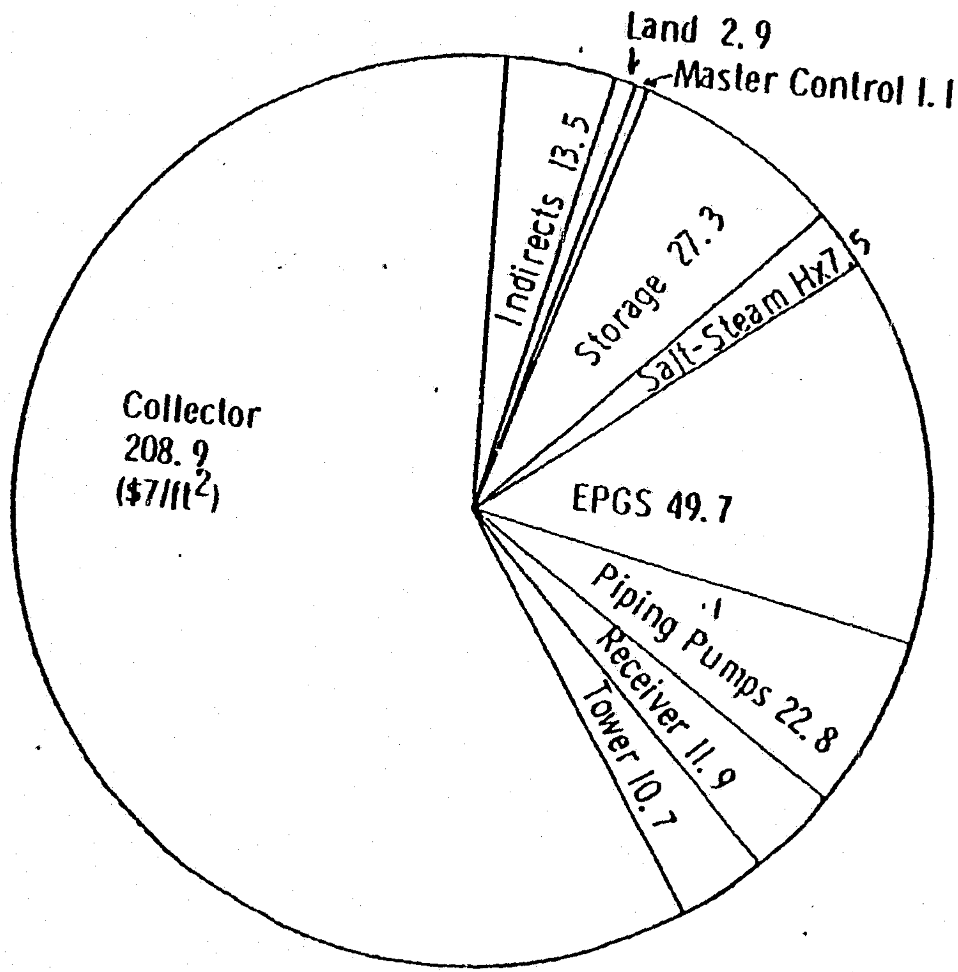


FIGURE 2-17. Tower Cost versus Tower Height

capital cost estimate for cavity and external receivers is related to the thermal power rating i.e., field area. For the external receiver, the cost[17] is \$36.75/m^2 (\$3.41/ft^2). For the cavity receiver the cost is \$46.40/m^2 (\$4.31/ft^2) of collector mirror area[17].

Figure 2-18 shows how various cost elements contribute to the overall cost of a PFCR (point focus central receiver) system (note that the heliostat costs are termed "collector" rather than "concentrator")[21]. The particular example shown is for a large (300MW) commercial system with nine (9) separate tower modules. Figure 2-19 shows how these relative costs might vary with the number of tower-collector modules[22].

The cost of heliostats is the sum of the various heliostat components as shown in Figure 2-20[23]. In addition, this figure shows an assumed reduction in heliostat costs with quantities produced. The reasons for a reduction in costs with increased production are summarized in Table 2-2. Another view of this experience curve approach to cost prediction is shown in Figure 2-21[23]. The source of this curve is the list price experience of the Model-T Ford automobile for the years 1909 through 1923, shown on the figure. The assumption is that the experience curve in \$/m^2 for heliostats will follow the same slope.



Total Capital Cost Estimates
\$356.3M (\$7/ft^2 Heliostats)
\$445.8M (\$10/ft^2 Heliostats)

Solar Multiple 2.28 on 21 June

Storage – Sized to Operate at Full Load for 24 Hrs on 21 June

Energy Cost Potential With
Modular Startup (Mills/Kw-Hr)

\$7/ft^2 Heliostats = 28.0
\$10/ft^2 Heliostats = 34.6

FIGURE 2-18. 300-MW_e Cost Pie Chart

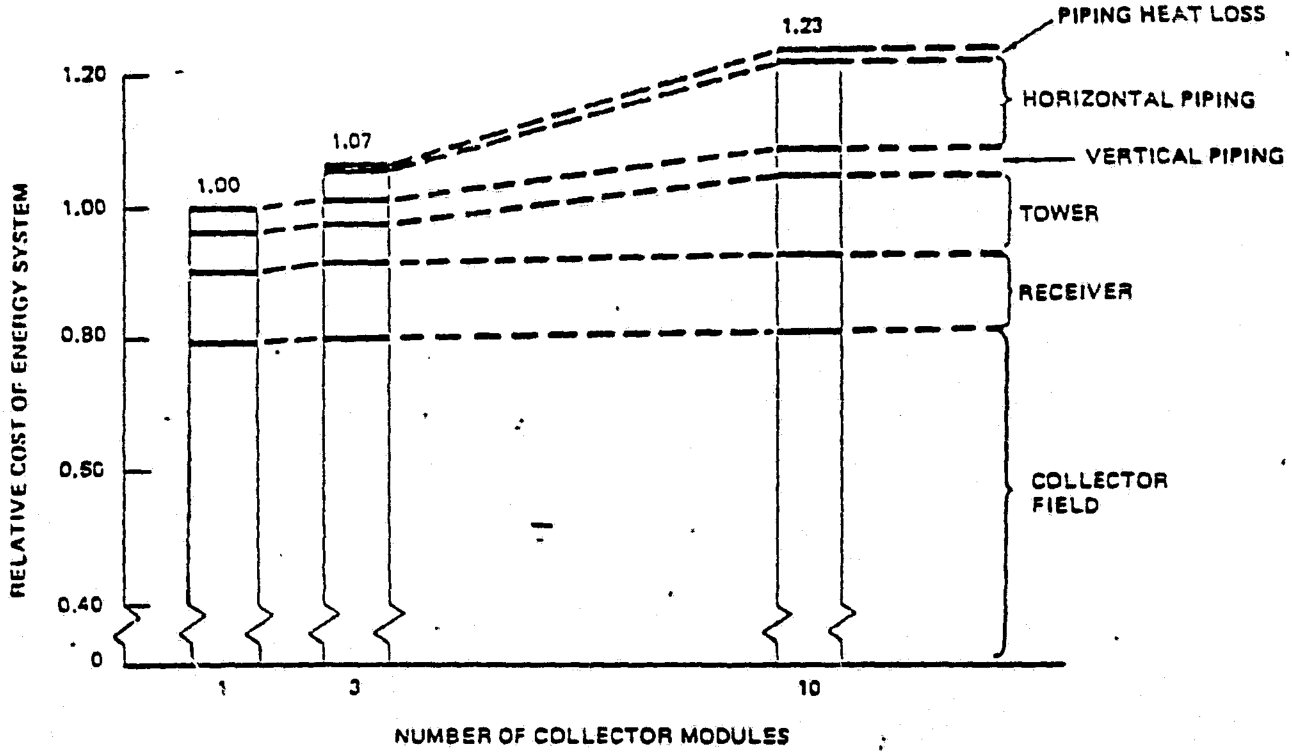


FIGURE 2-19. Impact of Multiple Modules of Cost
(506MW Peak Absorbed Power)

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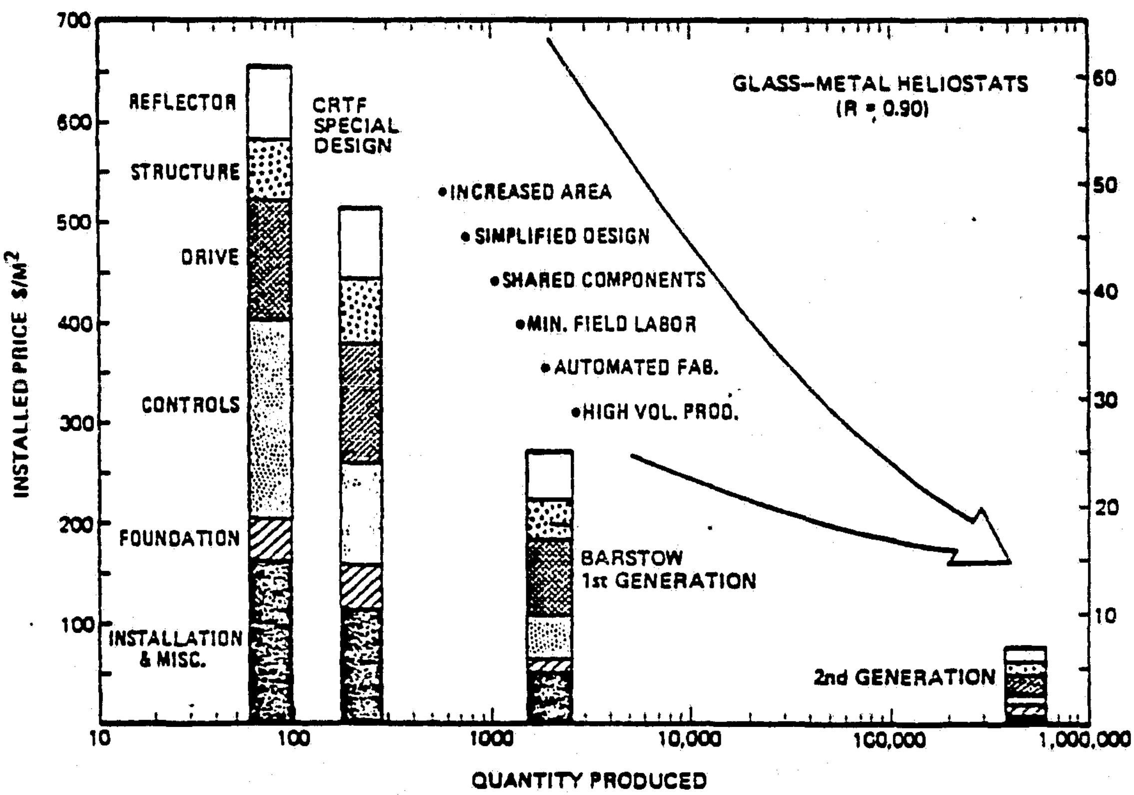

FIGURE 2-20. Heliostat Component Breakdown (1978 Dollars)

TABLE 2-2. Explanation of Cost Reductions

Increased Area	Incremental costs for larger components are generally less than purchasing two
Simplified Design	Off the shelf components, efficient assembly operations, standard tooling and relaxed tolerances have reduced initial costs
Shared Components	Field controllers spread over 10-100x more heliostats
Minimum Field Labor	Field assembly and alignment almost eliminated since field labor costs are double factory costs
Automated Fabrication	Production electronics, reduced manpower needs and interchangeable parts reduce fabrication costs
High-Volume Production	Unit costs spread over much larger population

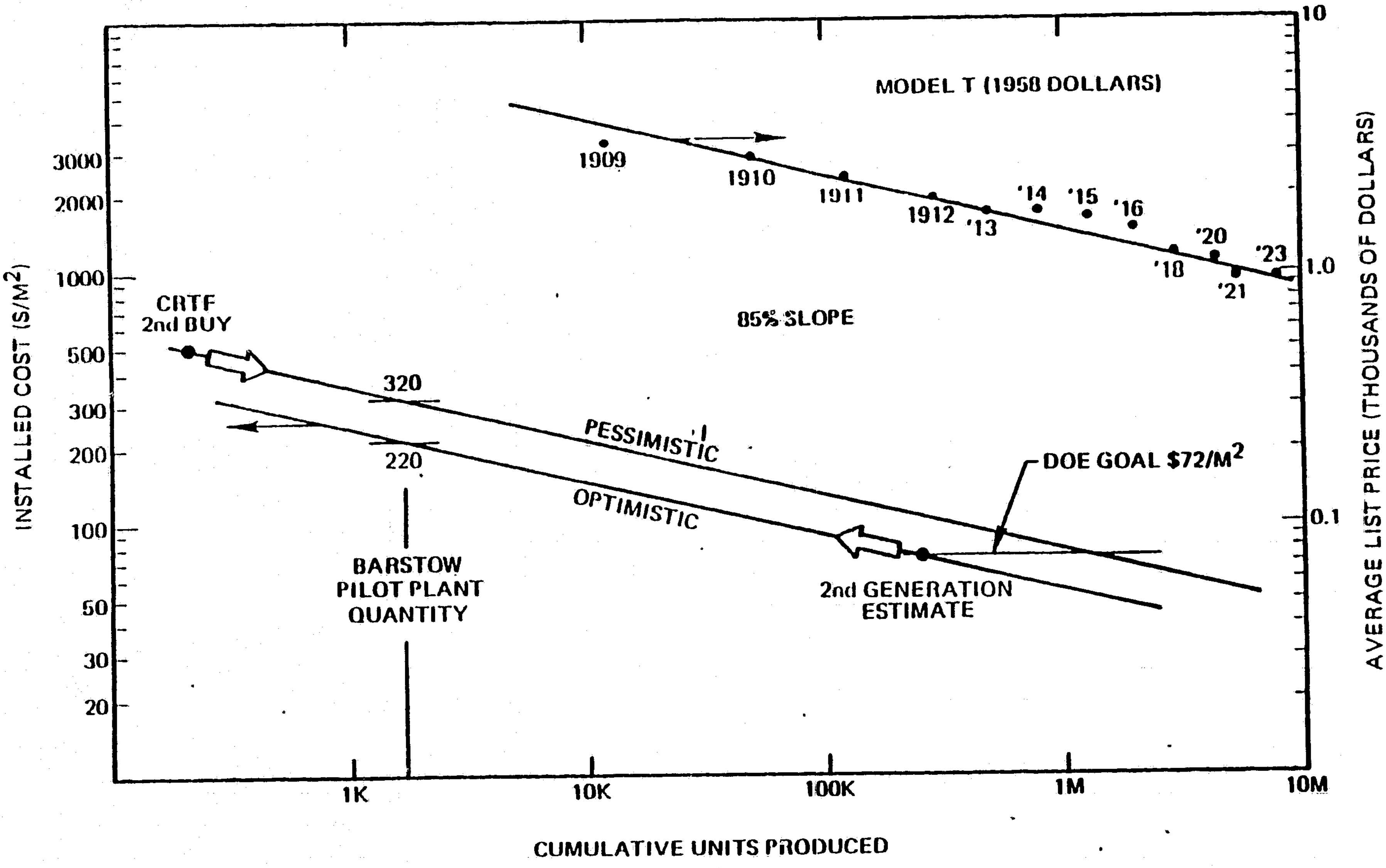

FIGURE 2-21. Experience Curve Comparison

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Tower costs can vary widely, depending on the assumptions made concerning the design requirements. A study was made to generate cost data for different tower configurations[24]. Table 2-3 shows the extreme values of results obtained. The main reasons for the wide variations are the differing assumptions for requirements for tower height, wind loads and seismic loads. Figure 2-22, shows the variation of height with output power level for both the cavity (north facing) and external (360^o) receivers[22]. Also shown is the <u>difference</u> in tower costs between the cavity and external cases. For the 100 MW commercial design[22], the absolute cost is on the order of $12M (13.50/$M^2$)for the tower and about $74M ($85/M^2) for the receiver (external type). The receiver costs run about 6 times the tower costs[22]. The external receiver was favored over the cavity receiver because the latter requires a taller tower and longer piping runs. This advantage for the external receiver is offset to some extent, however, by the higher heat losses experienced by the external design. Table 2-4 shows some cost estimates for PFCR heliostat-tower-receiver subsystems.

Operating and maintenance cost for the collector field and the external receiver is 23 mills/kWh[27] escalated at 7 percent per year.

TABLE 2-3. Extreme Costs—Steel Towers

TRIAL TOWER DESIGN NO.	TOWER HT. (FT)	COST (MILLIONS $)	RECEIVER WT. (KIPS)	GROUND ACCEL (G's)	WIND VELOCITY MPH
1	300	.270	200	.05	70*
13	300	2.978	8000	.60*	120
3	650	1.080	200	.05	70*
15	650	7.647	8000	.60*	120*

* CONTROLLING LOAD CONDITION

NOTE: 1 "KIP" = 10^3 LBF.

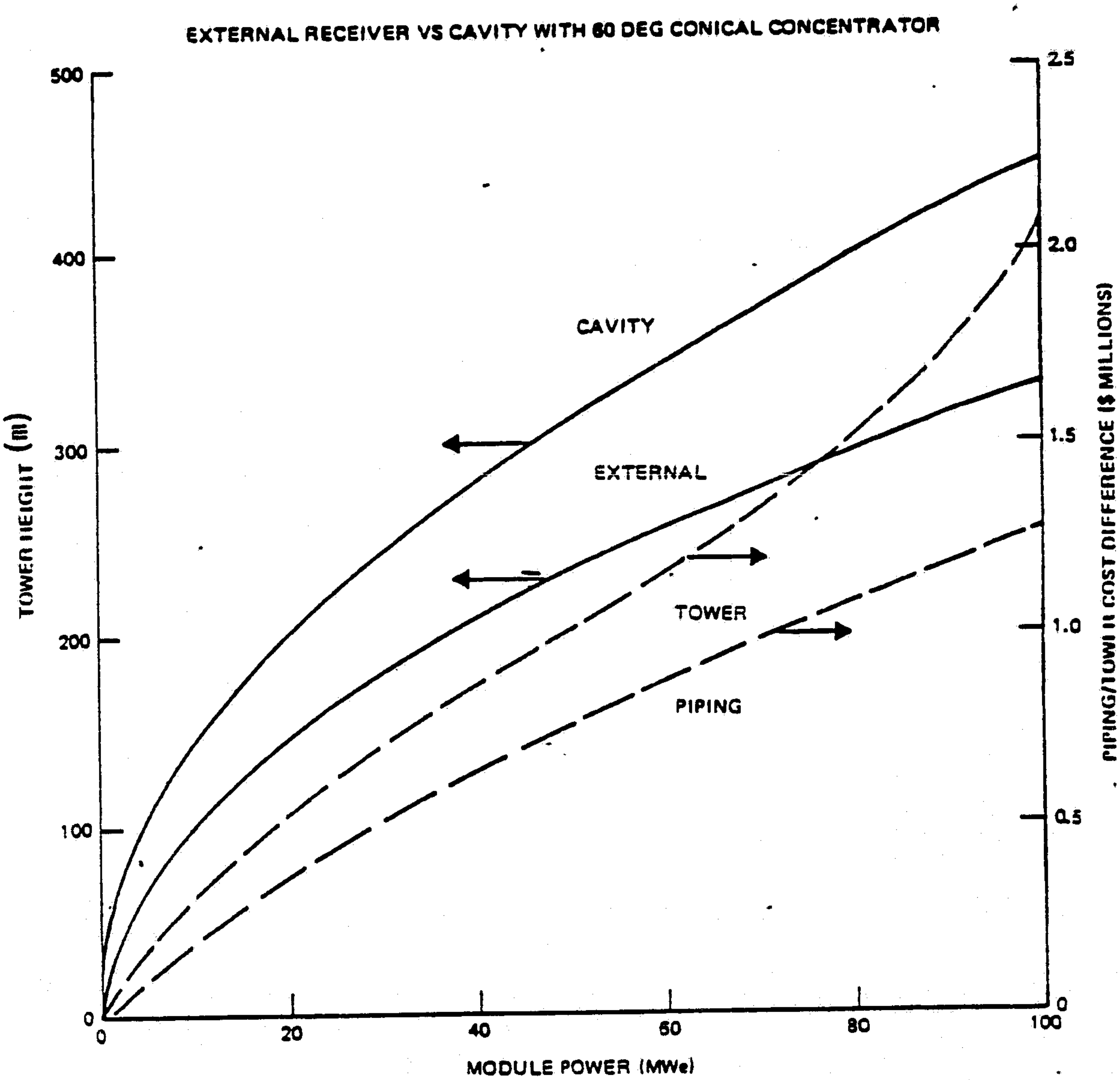


FIGURE 2-22. Tower Height and Cost Comparison

TABLE 2-4. Heliostat, Tower, and Receiver Costs for Point Focus Central Receiver (PFCR) Systems

REFERENCE	(21)	(22)	(23)	(23)	(23)	(24)	B&V	(25)	(26)	(26)	(12)	(42)	(43)	(43)	(43)
PLANT SIZE (MW)	300	10	-	-	-	-	-	5	10	100	50	10	100	100	100
NUMBER OF HELIOSTATS	69,399	1,760	-	-	-	-	-	-	-	20,415		1956	12,880 (5)	16,060 (6)	22,420 (7)
TOTAL HELIOSTAT AREA (m^2)	2.8×10^6	$.07 \times 10^6$	-	-	-	-	-	$.027 \times 10^6$	$\sim .08 \times 10^6$	$\sim .8 \times 10^6$	$.42 \times 10^6$	$.078 \times 10^6$	$.515 \times 10^6$	$.643 \times 10^6$	$.895 \times 10^6$
YEAR $	-	-	1978	1978	1978	-	1979	1978	-	-	1975	1979	1977	1977	1977
HELIOSTAT COSTS ($\$/m^2$)	75-108	406	650 (1)	300 (2)	70 (3)	-	75	59-91	~57	~57	65-145	370	62-150	52-150	62-150
TOWER & RECEIVER COSTS ($\$/m^2$)			-	-	-	-	-	40	~125	~45		172	26-38	22-32	18-25
TOWER COSTS ($\$/m^2$)	3.90	13.50	-	-	-	2-10 (4)	-	25	-	-		11	12	11	10
RECEIVER COSTS ($\$/m^2$)	4.30	85.00	-	-	-	-	37-46	15	-	-		161	14-26	11-21	8-15

(1) 10^2 Cumulative Units Produced
(2) 10^3 Cumulative Units Produced
(3) 10^6 Cumulative Units Produced
(4) Heliostat Area Estimated from Tower Height
(5) No Storage
(6) 2-Hour Storage
(7) 6-Hour Storage

Parabolic Trough Collector

The parabolic trough solar energy collector, shown in Figure 2-23 consists of a linear parabolic mirror, a receiver tube usually with one transparent cover tube, a support frame, and a tracking mechanism. The parabolic mirror, oriented by the tracking mechanism to follow the sun, intercepts the direct radiation and focuses it onto the receiver tube wherein the working fluid in the receiver tube is heated.

Some of the redirected energy, however, is lost by reflection, reradiation, conduction and convection. Numerous design features like selective absorbtion coatings on the receiver tube, selective transmittance of the cover tube, and high concentration factor, reduce thermal losses and permit the collector to operate effectively at moderately high temperatures. The loss in efficiency due to end effects when the sun is oblique to the axis is small for large length to width ratio collectors. The effective length of a collector is increased when many are connected together to form a continuous string. Such strings are usually oriented in an east-west (E-W) or a north-south (N-S) direction. The ratio of daily energy collected at the summer solstice to that collected at the winter solstice is significantly greater for a N-S orientation than it is for an E-W orientation. The variation in performance for a clear air insolation model is shown in Figure 2-24. The site location, the seasonal weather patterns (Percent sunshine), the load demand patterns and the seasonal diurnal value of the electricity produced, affects the choice of trough collector axis orientation.

Development of trough collectors has reached a rather sophisticated level. These collector systems have been installed in sizeable quantities in several demonstration projects as well as at numerous research and development sites. Reference (28) describes the various tradeoff considerations for different operating temperatures. The temperature of the working fluid can considerably alter the piping losses as well as the receiver performance. For example, for the McDAC system [28], the piping loss reduces efficiency by 4 percent at $423^{o}K$ ($302^{o}F$) and by

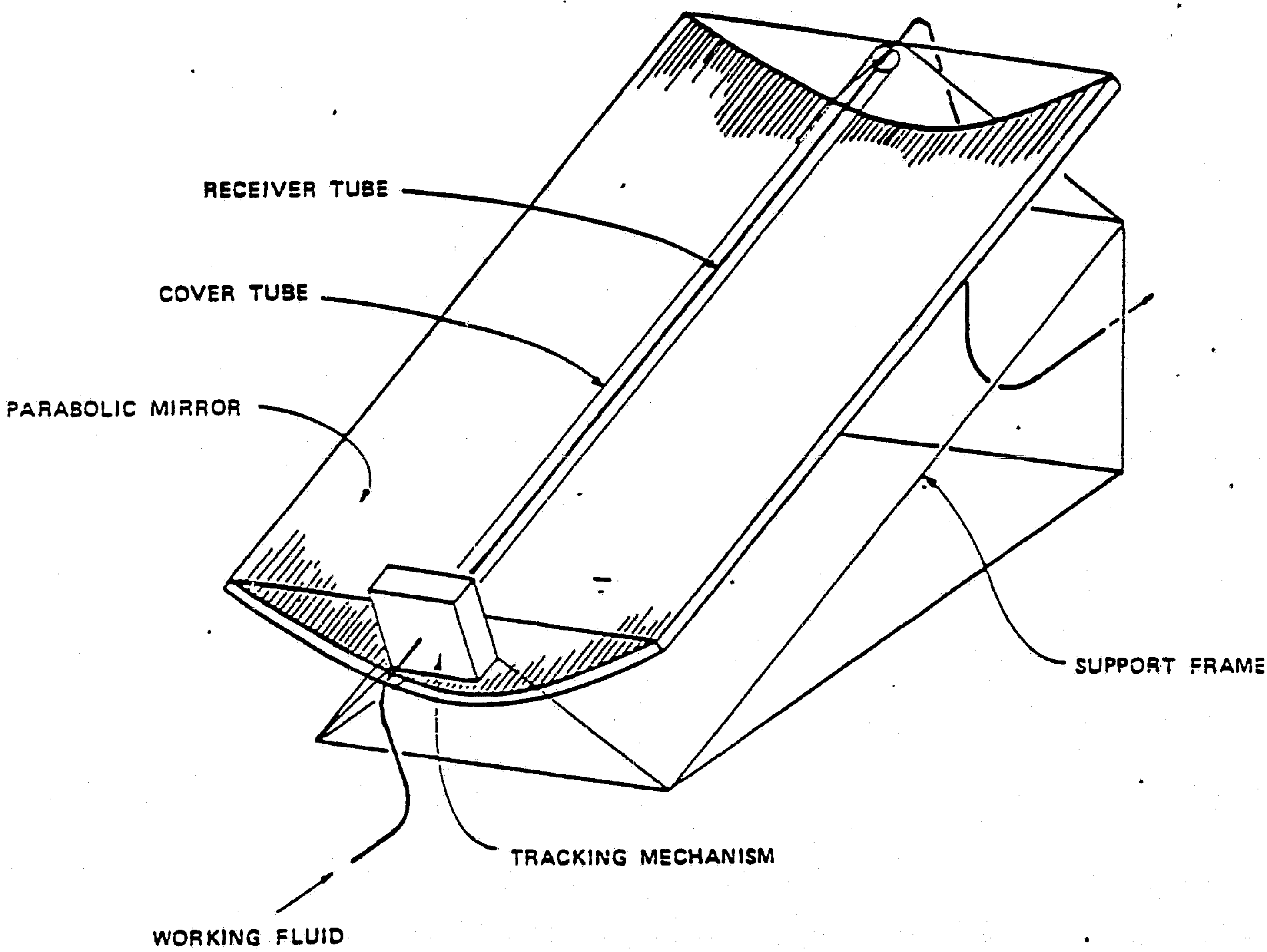
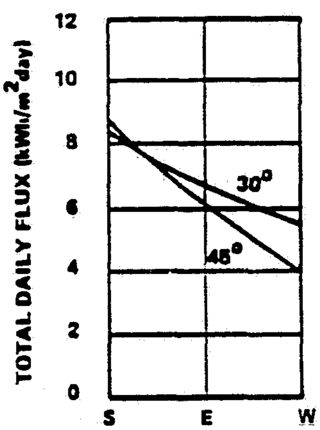
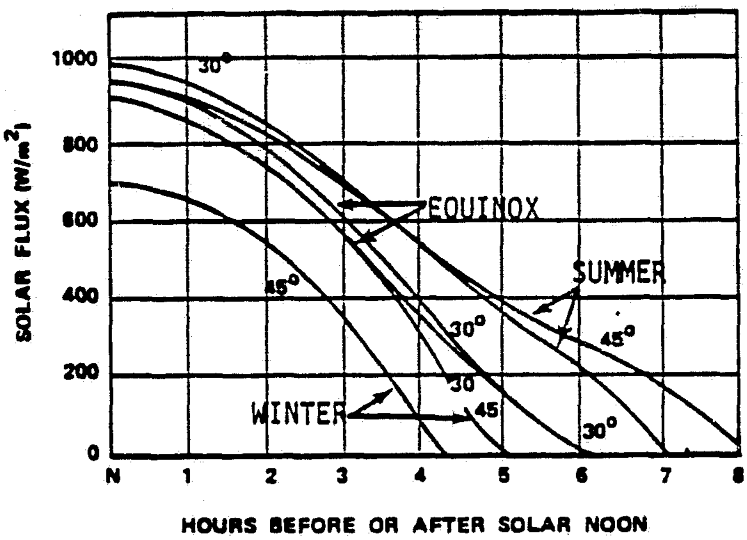


FIGURE 2-23. Parabolic Trough Solar Energy Collector

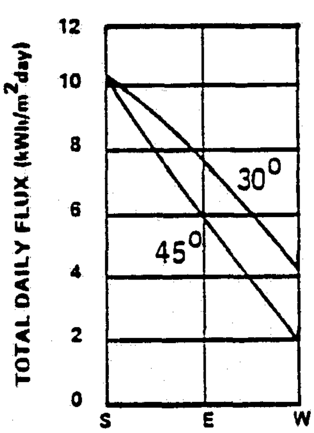


Daily Collector Yield

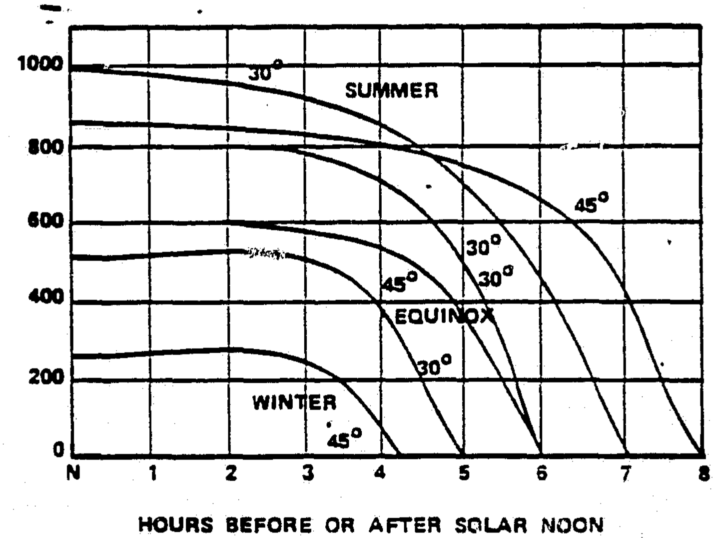


Hourly Variation of Solar Flux

E-W Orientation of Collector Axis



Daily Collector Yield



Hourly Variation of Solar Flux

N-S Orientation of Collector Axis (Tilted to Latitude)

FIGURE 2-24. EFFECT OF COLLECTOR ORIENTATION ON POWER AND ENERGY COLLECTED FOR TROUGH COLLECTORS (CLEAR AIR MODELS) FOR LATITUDES 30° AND 45°

9 percent at 623°K (662°F). Clearly such a change would influence the choice of investment in piping insulation or the choice of system operation. For the purposes of this study, a detailed site specific optimization cannot be treated. The parabolic trough system selected is representative of those found to be optimum in the studies cited.

Performance Projections

The current state-of-the-art development in linear parabolic trough collector systems does not leave much room for major performance improvements in the future. Anticipated areas of improvements in performance could include specular reflectivity of the mirror surface, tracking and pointing accuracy and selective absorbtion coatings for the receiver.

Component Availability

Trough collectors are currently commercially available from about a dozen vendors of which more than half are domestic. No problem in expansion of manufacturing capability is seen if the market impact studies show high penetration since the fabrication of trough systems is not a technologically difficult process.

Performance Model

The power absorbed in the working fluid, P_{ABS}, per module is given by:

$$P_{ABS} = (IRWL\tau\psi\alpha)\gamma - (P_c + P_r + P_{cn})$$

where ψ = (mirror slope error factor)·(shadow efficiency)·(tracking error correction factor)

γ = Incidence angle modifier

I = direct normal insolation (kW/m^2)

R = specular reflectivity of the mirror surface

W,L = width and length (m) of trough, respectively

τ = transmissivity of the receiver cover

α = receiver surface absorptivity

P_c = power loss by convection

P_r = power loss by radiation

P_{cn} = power loss by thermal conduction to the structure

Both the mirror slope error and tracking error correction factors account for the loss in energy collection efficiency. The mirror slope errors relate to limitations on the manufacturing process accuracy and mirror surface degradation that may occur during the operation of a collector system. The tracking or pointing error correction factor is used to account for image spreading that results due to pointing error. Data provided in Reference (20) on tracking error correction factor were curve fitted. The results can be expressed by an exponential function of the form, $\exp(-\delta^2/2\beta^2)$ where δ is the pointing error in degrees and β equals $2.0\bar{6}^{\circ}$. The shadow efficiency factor accounts for the fractional loss of energy due to shadowing of a collector or a row of collectors by other collectors in the field.

The shading efficiency, $(1-F_{sh})$, for long strings of collectors, i.e., not individually tilted troughs is given by:

$$(1-F_{sh}) = \begin{cases} 1-(1-1/N)(1-S_e \sin\phi/W)\,[1-(L^* \tan|AZ-AZ_o|)/W] \\ \text{if } \sin\phi \le W/S_e \text{ and } \tan|AZ-AZ_o| \le W/L^* \\ 1 \text{ otherwise} \end{cases}$$

where

N = number of rows of collectors of width, W, and length, L

S_e = row spacing, center-to-center distance between rows

ϕ = elevation angle of collectors

= $\tan^{-1}$ [tan El/ cox$(AZ-AZ_o)$]

AZ_o = azimuth of normal to the collector

and

$L^* = L$, if a single trough unit is used

$= N_c L$, if a string of N_c troughs are connected together making the effective length of the trough the length of the string.

For N-S oriented rows of collectors Acurex[20a] concluded that a good spacing is 3-1/3 times the trough width. This gave for Phoenix, Arizona, an annual shading efficiency of 0.93.

The incidence angle modifier, γ, a correction for the energy spilled at the ends of the trough and for the diminished collector area since the sun vector is at an angle to the normal to the aperture plane, see Figure 2-25, is given by Equation (19)[20].

$$\gamma = \left[1 - (0.52/L^*) \tan \alpha_i\right] \cos\alpha_i \qquad (19)$$

The angle of incidence, α_i, between the trough aperture normal and the sun vector depends on the trough orientation, and is given by Equations (20) and (21).

N-S orientation

$$\alpha_i = \sin^{-1} (\cos AZ \cos EL \cos TLT + \sin EL \sin TLT) \qquad (20)$$

E-W orientation

$$\alpha_i = \cos^{-1} \left[(\cos AZ \cos EL)^2 + (\sin EL)^2\right]^{1/2} \qquad (21)$$

where AZ, EL and TLT are, respectively, the solar azimuth, elevation and trough tilt angle.

The thermal losses were computed for a tubular receiver with selective absorption coating and a transparent enclosure. For this receiver configuration the heat loss by conduction is negligible[20] and the convective heat loss, P_c, is given by $hA_r\Delta T$ where h, A_r and ΔT are, respectively, the convective heat transfer coefficient, heat transfer surface (receiver) area, and temperature difference between the receiver surface and the ambient.

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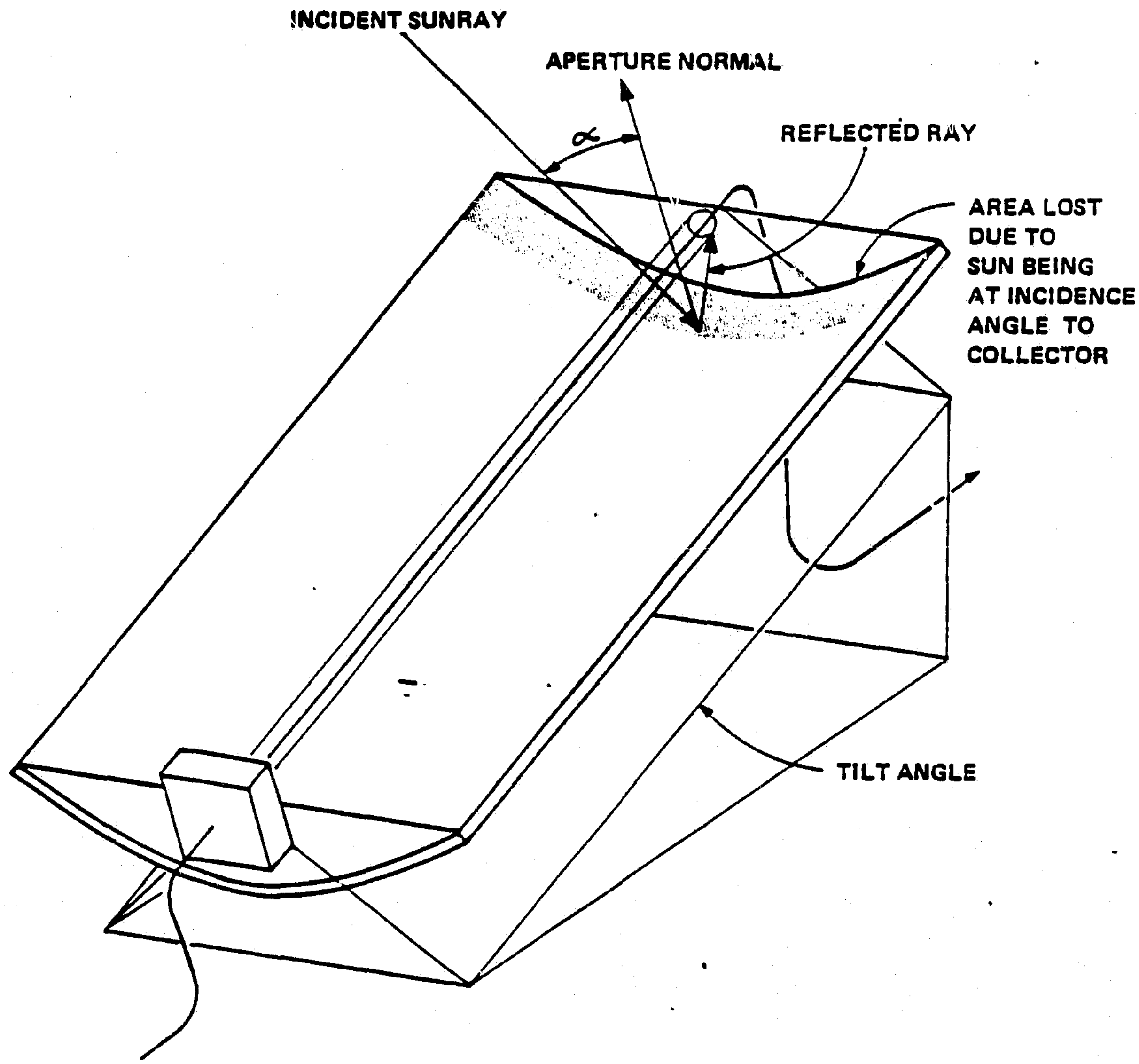

FIGURE 2-25. PARABOLIC TROUGH COLLECTOR SHOWING LOST EFFICIENCY CAUSED BY SUN RAY NOT NORMAL TO APERTURE PLANE

The radiative thermal loss, P_r, is given by equation (22).

$$P_r = \sigma \epsilon A_r \left[T_r^{\,4} - (\alpha/\epsilon)\, T_o^{\,4}\right] \qquad (22)$$

where σ, ε and α are, respectively, the Stefan-Boltzmann constant, emissivity and absorptivity of the receiver surface. T_r and T_o are the receiver surface and the ambient temperatures, respectively.

Cost Projections

The principal cost elements for the linear parabolic trough collector systems consist of the concentrator and receiver costs. Table 2-5 shows some cost estimates for parabolic trough collectors. Included in this table are estimates reported in Reference (29) from four vendors experienced in the commercial sale of these collectors.

Mature production trough collector cost estimates vary from under $\$100/m^2$ to over $\$200/m^2$.[20,28] The nominal values selected after careful review of literature and manufacturers data are based on the CSU/Westinghouse study[20], which shows the dependence of the collector costs on the trough width (W). For troughs 3 m or wider, the collector capital cost per square meter, in 1979 dollars is (\$102 - \$2.3.W) or \$80, whichever is larger. To this capital cost it is necessary to add the cost of collector field piping at $\$12.4/m^2$ of collector area.

Piping costs according to McDAC[28] range from \$21.5 to \$75.3 per square meter of collector area. In their market penetration study they used a nominal value of $\$37.7/m^2$ of collector area. In contrast, the CSU/Westinghouse study[20] shows piping costs to be 7 percent of the collector cost, e.g., about $\$7/m^2$. A nominal value for the piping cost is selected to be the average of the two, e.g., $\$22/m^2$ of collector area.

TABLE 2-5. Some Collector Cost Estimates for Parabolic Trough Systems

REFERENCE	(25)	(20)	(13)	(29)	(29)	(29)	(29)	(28)
TROUGH LENGTH (m)	-	-	-	2.44	1.83	3.05	3.05	-
TROUGH WIDTH (m)	-	-	-	.51	.51	1.83	1.22	-
YEAR $	1978	1979	1975	1976	1976	1976	1976	1979
NOTES	-	-	-	(1)(2)	(1)(3)	(1)(4)	(1)(5)	
COLLECTOR COSTS ($\$/m^2$)	105	87-107	129	48-51	235	160-240	100-172	200
CONCENTRATOR COSTS ($\$/m^2$)	75	80-95	103	-	-	-	-	-
RECEIVER (PIPING) COSTS ($\$/m^2$)	30	7-12	26	-	-	-	-	22-75

(1) Costs are for Current Production - Does Not Reflect Reduction for Future Production Experience
(2) Alburquerque Western Inc.*
(3) Beam Engineering
(4) Acurex Corp.
(5) Solartec Corpl

* The comparatively low cost of the Alburquerque Western device is due to its substantially lower performance design.

Fixed Mirror Distributed Focus Collector

The basic Fixed Mirror Distributed Focus(FMDF) collector system concept is displayed in Figure 2-26. This collector consists of a large fixed segment of a spherical mirror which focusses the incident solar energy on a linear receiver. The receiver length is approximately one half of the radius of curvature of the mirror. The flux concentration is highest in the vicinity of the paraxial focus and decreases rapidly towards the mirror surface. Trade-off studies under the Crosbyton Project[30][31] indicate that receiver lengths shorter than one half the radius of curvature can be beneficially deployed.

The receiver is rigidly attached to a boom which is pivoted on a 2-axis mount to follow the sun's motion. The mount's drive system incorporates both open loop (clock drive) and closed loop (photovoltaic detectors) tracking control. The mount is fastened to a stationary support structure located over the spherical mirror.

The working fluid (such as water/steam) pumped through the receiver absorbs the thermal energy which is transferred to an energy conversion unit via an appropriately designed and insulated piping network. The spent working fluid is discharged from the prime mover, reduced in temperature and pressure, and recycled through the receiver.

Extensive analysis of the FMDF system conducted under the Crosbyton Project has suggested that a 61 m (200 ft.) aperture diameter collector with the aperture plane tilted by 15^{o} to the south is about the optimum collector size. An FMDF-SPS plant will consist of a large number of collector modules which can be either interconnected to deliver thermal energy to a central energy conversion unit or in concept operated as individual power generators with each collector module having its own energy conversion unit. The collector field with a 25 percent ground cover ratio provides a negligible loss of energy due to shading. This ground cover ratio is achieved with collector rows, (collector tilt 15^{o}) separated by one aperture diameter. Studies with collector row separations

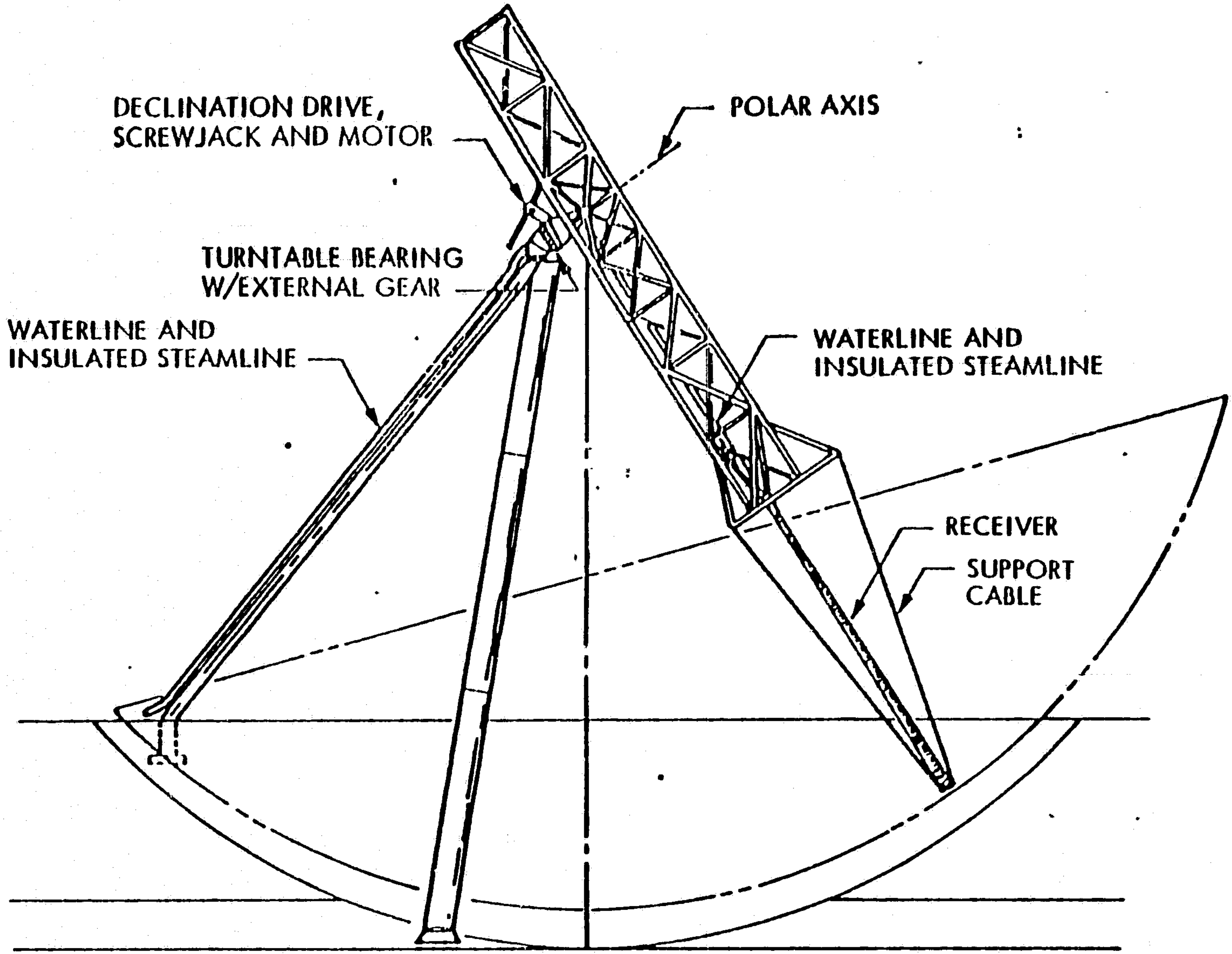

FIGURE 2-26. Fixed Mirror Distributed Focus Concept

of 0.5 and 0.75 of the aperture diameter suggest that energy lost by shading is not off-set by reduced thermal losses and gains in cost reduction of the thermal piping network.

Performance Projections

The FMDF collector system is currently in the development and testing phase. Performance improvements can be anticipated in several areas as the production designs are developed. The current design of the receiver entails radiative and convective thermal losses of about 15 percent. Use of convection suppression methods and improvements in receiver surface absorptance are projected to enhance receiver performance in excess of 5 percent. In addition, a variety of reflective mirror panels are being tested by E-Systems[32]. An improvement of around 10 percent for the concentrator performance can be anticipated by 1985 from utilization of (a) higher reflectivity (95 percent) mirrors being developed by Owens-Corning, and (b) better manufacturing processes leading to enhanced quality of reflector panels.

Various low cost materials for the FMDF concentrator and receiver subsystems are currently in evaluation. Results of these studies could provide potential gains in collector performance per unit cost. At present, the extent of resulting gains in collector performance from the use of the alternative structural materials cannot be projected.

Moreover, although performance improvements can be expected from improved receiver tracking and pointing accuracy the resulting gains are considered to be marginal.

Component Availability

Presently, there is no commercial production of FMDF collectors. Prototype systems are being developed and tested in both the United States

and France. Substantial experience in the production and technology already exists for the related radiotelescope and communication antenna systems. Other solar thermal projects in progress under sponsorship of the U.S. Department of Energy can be expected to add to the technology and manufacturing base that will ensure availability of these collectors by 1985.

Performance Modeling

The available data from the Crosbyton Project provide Equation (23) for the thermal power, P_{ABS}, collected by a FMDF collector per unit aperture area.

$$P_{ABS} = (\rho \alpha I) F_t - P_{loss} \tag{23}$$

where ρ, α, I, F_t and P_{loss} are, respectively, the mirror reflectivity, receiver surface absorptance, direct normal insolation, receiver effective tracking factor and thermal loss from the receiver.

The nominal FMDF collector selected for modeling has a mirror reflectivity, ρ, of 0.88 and a receiver surface absorptivity of 0.90. The concentrator has a 60^o rim angle and is tilted 15^o to the south. In addition, the optics is practical with the total surface, tracking and pointing error of 0.5^o. For this configuration, receiver effective tracking factor, F_t, a function of the instantaneous angle of incidence, Θ_i (the angle between the sun vector and normal to the mirror aperture), is given by:

$$F_t = \begin{bmatrix} \cos \Theta_i (1 - 0.16 \sin 2 \Theta_i); & \Theta_i \leq 70^o \\ 0.9 \cos \Theta_i & ; \Theta_i > 70^o \end{bmatrix} \tag{24}$$

For the FMDF collector, the concentration varies rapidly along the receiver length. This variation amounts to a concentration of several hundred near the paraxial focus to about 30 at the receiver

end close to the mirror surface, if the total error including the size of the solar disc, surface errors and tracking and pointing errors is 1^o. Since the concentration along the receiver is high, the conduction losses from the receiver to its support structure are negligible compared to the convective and radiative heat losses. Then the total thermal losses are given by equation (25)

$$P_{loss} = \sigma \epsilon A_r(T_{s_1}{}^4 - T_o{}^4) - h_{ext} A_r(T_{s_1} - T_o) \qquad (25)$$

where σ, ϵ , A_r, T_{s_1} T_o, and h_{ext} are, respectively, the Stefan-Boltzmann constant, receiver surface emissivity, receiver area, the outside wall temperature, the ambient temperature and the external convection coefficient.

For a unit concentrator aperture area, $A_r/(1)$ can be defined as $(^1/C)$ where C is the geometric optical concentration factor. Then

$$C\ P_{loss} = \sigma \epsilon (T_{s_1}{}^4 - T_a{}^4) - h_{ext} \cdot (T_{s_1} - T_a) \qquad (26)$$

The typical operation of an FMDF collector involves a once through flow receiver design with the inlet heat transfer fluid entering at the low concentration end, gaining in temperature and exiting at the high concentration end at a temperature specified by the thermodynamic cycle selected. Thus, in equation above the variables C, and T_{s_1} are taken to be functions of the position coordinate along the length and circumference of the receiver.

Next, to determine P_{loss} at any position along the receiver, T_{s_1} must be determined. At any radial position T_{s_1} can be expressed as:

$$P_{ABS} = \left(\frac{1}{\frac{1}{h_i} + \frac{t}{k}}\right)\left(T_{s_1} - T_f\right) \qquad (27)$$

where h_i is the internal convection coefficient, k is wall conductivity, T_f is the bulk internal fluid temperature, and t is the wall thickness.

From equating the two equations for P_{ABS} a quartic equation is obtained from which T_{s_1} is easily computed. The overall thermal solution requires two additional equations, namely

$$P_{ABS} \cdot \Delta A_r = \dot{m} \; \Delta H_f \text{ , and} \tag{28}$$

$$T_f = f(H_f, P) \tag{29}$$

where $\dot{m}$ is the mass flow rate through the receiver area element, ΔA_r, and ΔH_f is the fluid enthalpy change from inlet to outlet of the element. The function f is the equation of state of the fluid, i.e., steam table data for the water/steam thermodynamic cycle or property data for any other heat transfer fluid utilized.

In modeling the performance of the FMDF collector appropriately, a momentum balance equation is required, in addition, to define incremental pressure drop. However, initial calculations can be performed with pressure as constant without a significant loss in accuracy particularly if approximate values of the pressure drop are computed and included in the energy balance equation. Moreover, variations in material thermal properties and heat transfer coefficients as a function of receiver position, temperature, etc., need not be considered in a study directed at examining the impact and requirements definition of FMDF-SPS systems. Rather, these values will be assumed constant.

The combination of mirror aperture diameter, the number of FMDF modules and their geometric arrangement, the thermodynamic cycle selected, and the specific site factors (insolation) fix the capacity of the FMDF solar plant. Figure 2-27 displays the inputs and outputs of the FMDF collector to specify the plant performance

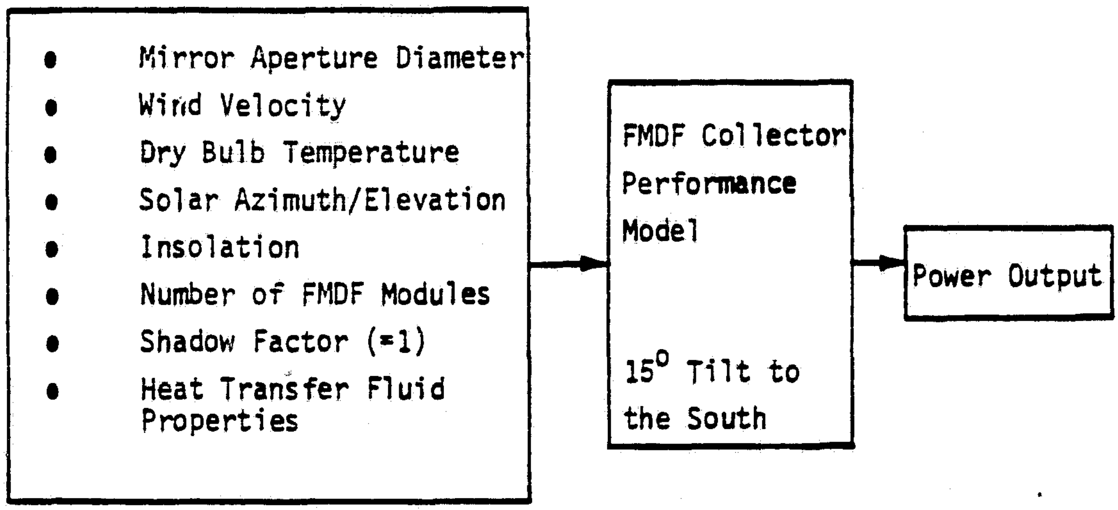

FIGURE 2-27. Inputs and Outputs for the FMDF Collector System

Cost Projections

Cost projections for the FMDF collector are based on the Crosbyton Study[30,31]. Figure 2-28 shows the variation of FMDF collector costs with concentrator diameter. The concentrator, support structure, and receiver costs tend to increase with diameter. Items that balance this are the tracking and controls, and the piping system which both decrease in cost (per unit aperture area) with increasing diameter. Mirrors and panels, the major cost items, essentially do not vary with diameter. The overall costs then show a minimum around the 61 m (200 ft.) diameter. The capital cost in 1979 dollars shown in Figure 2-28 for the FMDF collector was curve fitted as a function of the aperture diameter. A 7 percent annual escalation factor was applied to the data for 1977 presented in Figure 2-28. The resultant equation is:

$$(\$/\text{Aperture}) = (297.1 - 3.51\,D + 0.0294D^2) \qquad (30)$$

where D is the aperture diameter in meters.

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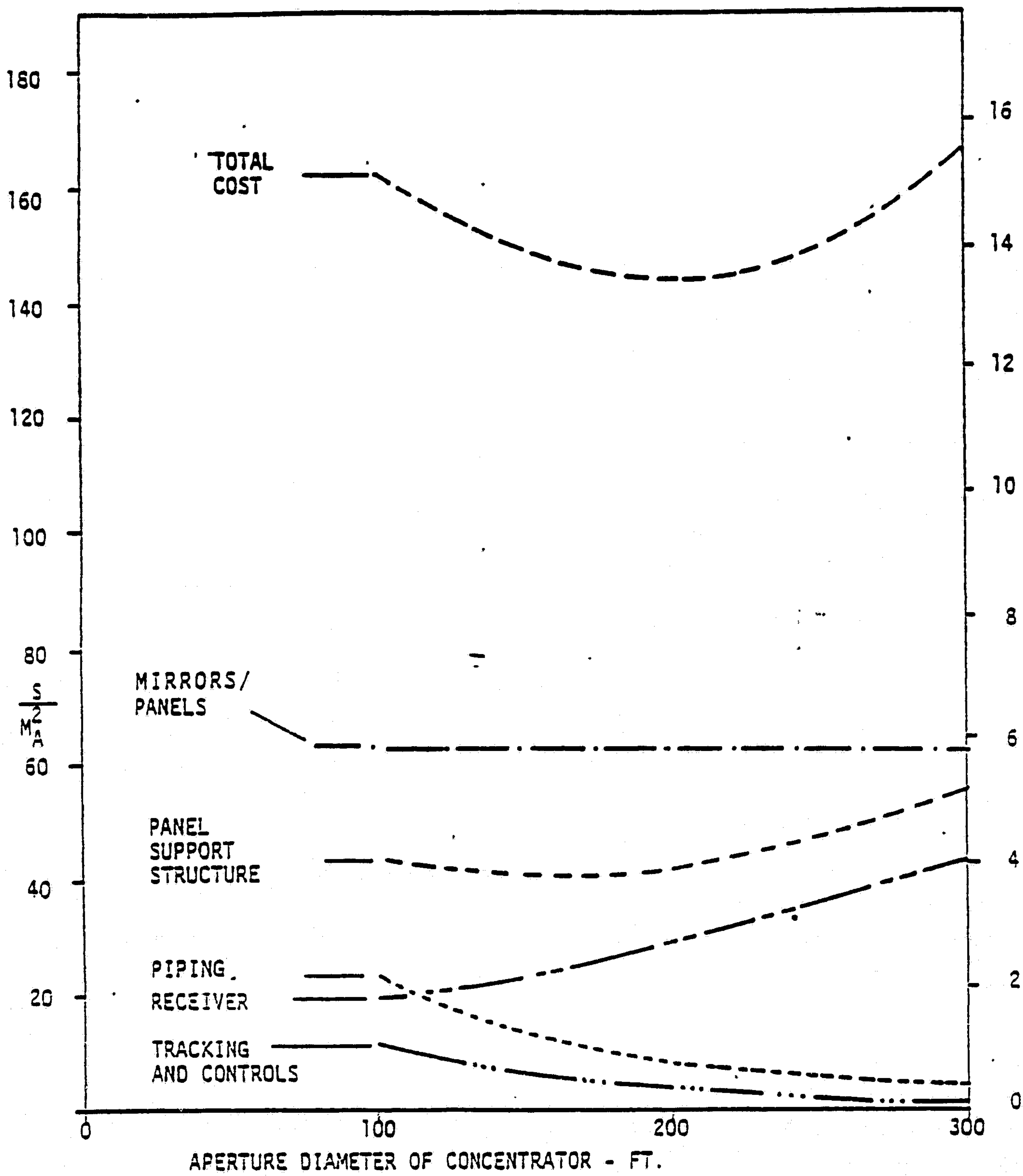

FIGURE 2-28. Collector Component Production Costs as a Function of Size

Table 2-6, shows estimates of FMDF collector costs for a current (Crosbyton System) design as well as a production design reflecting cost reductions due to increased production experience. In contrast, Reference (14) shows a substantially lower cost estimate for two reasons. First, these estimates are not in current dollars. Second, they do not include all costs included in more recent estimates presented in Reference (32). The latter cost projections are considered to be more realistic since they are based on current experience with the development of prototype collectors for the Crosbyton System.

TABLE 2-6. Cost Estimates for FMDF* Collector System

REFERENCE	(31)	(31)	(14,29)	(32)
DISH DIAMETER (m)	61	61	-	61
YEAR $	1978	1978	1976	1979
CONCENTRATOR COST ($/m^2)	257(1)	151(2)	53(2)	89(2)
RECEIVER COST ($/m^2)	101	50	-	-

* FMDF—Fixed Mirror Distributed Focus
(1) Current (Crosbyton) Design
(2) Projected Production Deisgn

2.2.4 Energy Transport System

The energy transport system provides the means to coalesce solar energy (power) generated at each collector. Two options exist for bringing the energy together. The thermal option is to coalesce the heat transfer fluid at a common point before it is directed to a heat engine. The electric option is to convert the thermal energy at each collector unit into electricity and then bring the electric power together at a common point.

Thermal Energy Transport

Thermal energy transport is applicable for the Rankine thermodynamic cycles only. The Brayton and Stirling cycle engines are not candidates for thermal transport for two reasons. First, the low specific energy of the working fluid would require very large volumes of the working fluid to be transported by a transport system with very low pressure drop, a costly system. Even small pressure drops in the cycle outside of the actual expansion stage cause serious degradation of cycle efficiency. Second, these engines operate at very high temperature, 1100°K (1500°F), and require very expensive materials for the high temperature strength and corrosion resistance to perform with a satisfactory lifetime. Thermal transport, therefore, is limited to the Rankine cycle systems. Thermal loss for the piping system depends on the piping dimensions (length, diameter), temperature of its contents, its insulation, the air temperature and the wind speed. It is almost independent of power level when the system is operating. However, analysis of numerous systems has shown that the use of a loss factor proportional to the energy converted is reasonable[21,33]. For the market penetration and impact analysis study, the approach of a thermal energy transport loss factor introduces minimal errors. For example, if the loss was 0.5 percent and the solar plant operated 10 hours out of the 24 hours, the total loss would be (24 x 0.005). Since the solar plant is regarded to produce power only 10 hours of the day, the energy output is 10 units and the effective daily loss ratio is 1.2 percent. The difference in energy production over the 10 hour day in the example using the 1.2 percent for 10 hours to the more exact fixed loss of 0.5 percent for 24 hours is 4.2 minutes at rated operating level. Since the impact analysis uses 1 hour increments of time, no serious error occurs. Furthermore the "error" is made-up by the end of the twenty-four hour cycle. The 1.2 percent of the power loss includes an allowance for diurnal cooling and reheating of the piping system.

Electrical Transport

The wiring network for electrical transport is based on trade-off studies between loss of energy, size of the conductors, and cost of installation. The results are sensitive to site specific factors, however, the overall impact on the cost of electricity is small. Based on studies done by the Division of Central Solar Technology(34), the cost of the electric wiring system for distributed systems is 2.2 percent of the plant cost and the average power loss is 3 percent of power.

2.2.5 Thermodynamic Cycles

The conversion of heat energy into mechanical work is accomplished by heat engines. Heat engines use various thermodynamic cycles to convert the thermal energy added to the working fluid in one portion of the cycle into rotational or oscillatory motion doing mechanical work. For solar applications external combustion engines are used. These engines are characterized by heat being added to the working fluid through a heat exchanger - the solar receiver. The one exception to the external combustion criterion is the hybrid operation of an air open Brayton cycle engine where fuel can be added directly to the air, is burned, and its heat of combustion increases the thermal energy of the working medium.

For solar engines, three thermodynamic cycles (Rankine, Brayton, Stirling) can be used. For the Rankine cycle, the working mediums used are water and toluene; for the Brayton cycle, both open and closed cycles using air as the working fluid have been modeled. The Stirling engine working fluid is helium although air and hydrogen are also candidate working fluids.

The selection of the model details for the SPS impact analysis requires that the model permit the determination of performance characteristics and their sensitivity to input variables. The internal details to which the engine is modeled is secondary to the requirement that it permits the tracking of energy (power) into and out

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of the system. Furthermore, the estimates of engine performance and characteristics are for a future timepoint 1985-1999. Thus we have developed a composite estimate of engine performance based on the results of extensive literature review, personal contact with vendors and developers. In cases where large variations in performance estimates for new engines exist engineering appraisal of technological risk, material developments, and lifetime expected of each candidate lead to a consensus on the composite performance estimate. These estimates are aimed at the criterion of the "most likely optimistic value" that one would have in the time frame being modeled. The meaning of the words "optimistic values" is what can be reasonably expected to be achieved under favorable conditions with today's advanced technology and materials. The changing availability of certain alloying materials was not factored into these estimates.

Open Brayton Cycle

The open Brayton Cycle is shown in schematic form in Figure 2-29. Its operation is illustrated in the temperature-entropy diagram,

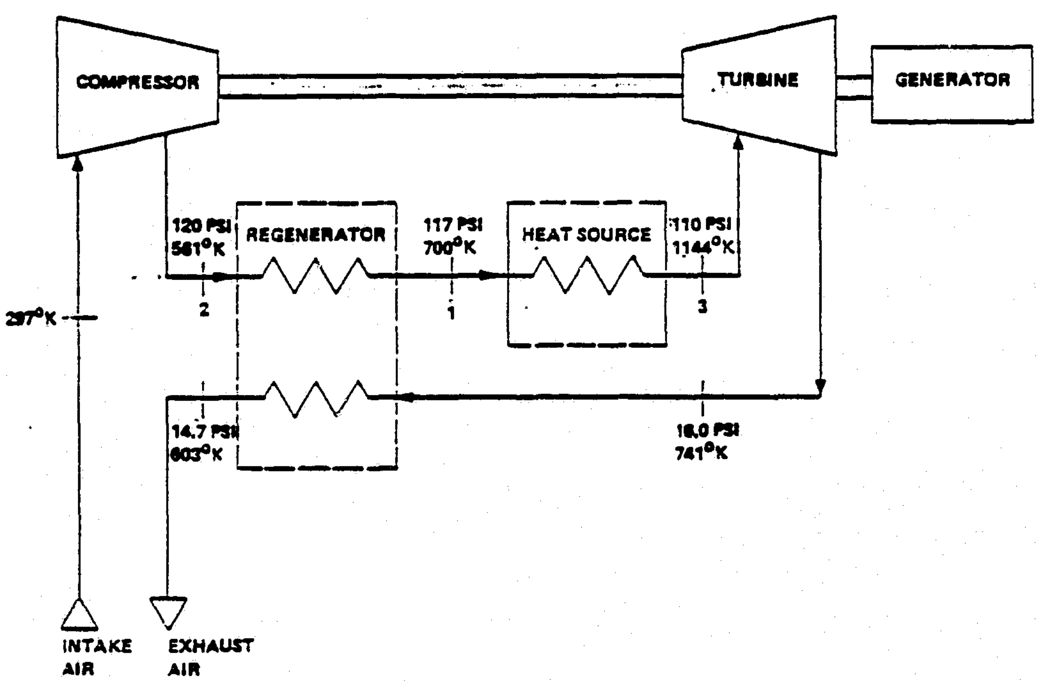

FIGURE 2-29. Regenerative Open Brayton Cycle Flow Schematic

Figure 2-30. The first step, from state 1 to state 2, for the ideal open Brayton cycle is the adiabatic compression of ambient air. Compression is achieved by means of a turbine driven compressor. The process from state 2 to 3 is the isobaric addition of heat to the air via a solar receiver or fossil fuel combustor. The receiver and combustor may be utilized alone or in a hybrid combination. During adiabatic expansion of the air through the gas turbine which occurs from state 3 to state 4, mechanical energy is extracted from the working fluid. Electric power is produced in this step by the turbine-driven generator. To complete the cycle, turbine exhaust air is expelled to the atmosphere which acts as an infinite heat sink. Cooling of the turbine exhaust air by the atmosphere, although not requiring any equipment, is represented by the process line from state 4 to state 1.

A cycle variation, shown by dotted lines on Figure 2-29, is made by adding a regenerator to the system. In the regenerator, heat in the exhaust air is transferred to the high-pressure air leaving the compressor. The result is an increase in cycle efficiency. However, addition of the regenerator does introduce another pressure drop in the system. This pressure drop must be balanced against the increase in heat added.

Electric power production requires the turbine to maintain a constant rotational speed. Because of this requirement, single shaft gas turbines - machinery with the turbine and compressor mounted on a common shaft - are constant volume machines. Therefore load is not controlled by varying the mass flow rate but by modulating the turbine inlet temperature. The less common two-shaft gas turbine, which is not a constant volume machine, is more complex to control but does not suffer the loss in efficiency at part load. The trend for solar applications is to go to variable volume (multishaft) engines in the larger ratings 1-10 MW_e. For the small engines the single shaft machine is used. An option which is not modeled is a variable speed generator with electrical equipment for conversion to the operating power frequency.

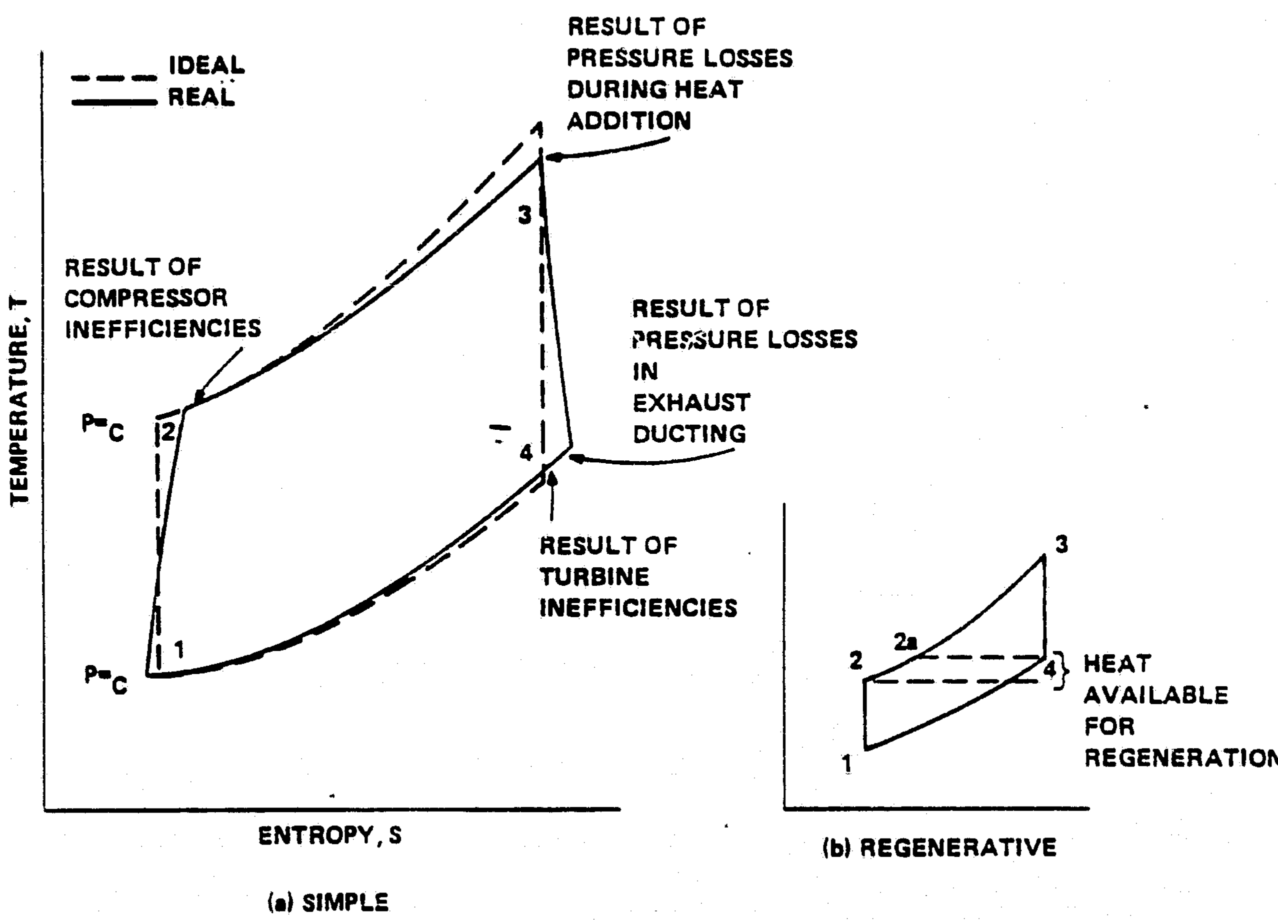

FIGURE 2-30. IDEAL OPEN BRAYTON CYCLE T-S DIAGRAM

The open Brayton cycle has several unique characteristics. First, because the cycle is open and the air is utilized as the working fluid, no heat rejection equipment (e.g., condensers, cooling towers, etc) and essentially no water are required. Also, the supply of working fluid is guaranteed, regardless of plant location. Another significant characteristic of the open Brayton cycle is the large amount of work required to drive the compressor. This large amount, typically about 50 percent of turbine output, is required since air has a high specific volume. Finally, the open Brayton cycle is well suited to hybrid solar/fossil operation. A fossil fuel combustor, which can be placed in parallel or series with the solar receiver, is utilized to supplement heat added to the air by the receiver.

Performance Projection

Black & Veatch has developed a significant amount of experience with solar powered open Brayton cycles in recent years. Performance data from previous projects, along with new data supplied by Garrett Corporation's Airesearch Manufacturing Company, were used in developing the performance predictions. The projected performance is based on expected component design and materials improvements to currently available engines.

To permit sizing of the engine, all performance models have been developed on a "per unit" basis. Thus, the rated thermal energy input to the engine is 100 percent. Two size classes of engine were chosen. The first 1-10 MWe for central receiver systems. The second 10-25 kWe for point focusing parabolic dish systems. For each size class the geometric midpoint rating 3 MWe and 16 kWe respectively were modeled and are representative of the performance of engines in their class.

Overall engine efficiency at design point conditions and at rated output for the time frame 1985-1989 is 0.365 for 1-10 MWe units.

For the 1990-2000 time frame the engine efficiency is 0.423. These values are to be compared to approximately a 0.31 efficiency available today. For the 10-25 kWe units the overall efficiency projections are 0.300 for the present time through 1989 and 0.339 from 1990 through 1999. For the part load performance, correction factors are used which, on a per unit basis, are the same as for the current engines. This is a valid assumption since the behavior of the engine is controlled by its fluid characteristics.

Component Availability

There is no known reason to expect that engines would not be available in the time frame being considered if the market demand exists. Open Brayton engines are commercially available in the required rating from those firms shown in Table 2-7. Delivery time for these engines should be 6-12 months irrespective of engine rating.

Cost Projections

Estimates of costs of mature open Brayton cycle engines are based on actual prices of current production as reported in "Gas Turbines," a monthly trade magazine (35) The price on a per kWe basis for 1-10 MWe units varies from $175 to $245. A nominal figure of $225/kWe is chosen based on the fact that a high performance engine is desired. These prices are representative of mature production but probably would be reduced to $180/kWe if very large production volumes occurred. Cost estimates for the 10-25 kWe engines were supplied by Airesearch Manufacturing Company as there is no current production of such units. They estimated costs at $500/kWe. However, mature mass production should be able to reduce the costs to $250/kWe in the 1990-1999 time frame.

Operating and maintenance (O&M) costs are estimated to be the same for the 1985-1989 and the 1990-1999 time periods - $0.015/kWh for the 1-10 MW machine and $0.020/kWh for the 10-25 kW machines.

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TABLE 2-7. Open Brayton Cycle Engine Availability

MANUFACTURER	MODEL #	RATING
CURTIS-WRIGHT CORPORATION	POD 9 POD 10	6,950 KW 9,300 KW
DETROIT DIESEL ALLISON	501 KB	3,700 KW
GARRETT CORPORATION - RESEARCH DIVISION	IE 990	3,960 KW
GENERAL ELECTRIC COMPANY	1502	3,700 KW
INTERNATIONAL HARVESTER CORPORATION SOLAR DIVISION	GEMINI TITAN SATURN CENTAUR MARS	30 HP(22 KW) 150 HP(110 KW) 1,146 HP(850 KW) 3,860 HP(2.85MW) 2,500 KW 7,000 KW
NORTH AMERICAN TURBINE CORPORATION	VIKING I VIKING V	1,425 KW 2,710 KW
ROLLS ROYCE LTD.	RB-211	28,960 HP(21.7MW)
RUSTON GAS TURBINES, INCORPORATED	TA 1750 TB 4000	1,283 KW 2,817 KW
SULZER BROTHERS, INCORPORATED	1 3	3,950 KW 5,300 KW

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Performance Modeling

The modeling of the open Brayton cycle requires the simultaneous matching of (1) the turbine inlet temperature to the solar receiver outlet and (2) the turbine input power to the solar receiver output power. Evaluation of alternate methods led to the method of describing the Brayton cycle in terms of its input power and calculating the turbine inlet temperature (TIT) and the turbine efficiency. In this approach the turbine inlet temperature is not explicitly used for the turbine performance calculations, it is only used to calculate the radiation loss from the receiver. Through an iterative algorithm, receiver output power and temperature are adjusted to match the turbine input power (TIP) and temperature. The turbine output power can then be calculated by means of the efficiency versus input power curves including appropriate corrections for ambient environmental conditions. The empirical relationship of TIT/TIP rated is shown in Figure 2-31.

The input parameters for the modeling are the power rating of the turbine, the design maximum turbine inlet temperature, the atmospheric pressure, the atmospheric temperature, and the power input to the turbine generator. The overall efficiency of the open Brayton cycle as a function of input power is shown in Figure 2-32 for the 10-25 kWe engine and Figure 2-33 for the 1-10 MWe engine. The overall efficiency includes the generator and other losses associated with the cycle. The slight inflection in the curves for the 10-25 kWe engine is due to the cubic polynomial curve fit of the real engine data. The actual deviation from a cubic spline fit of the original data is less than 0.1 percent. The use of the curve fit for the full range of per unit turbine input power is a sensible modeling procedure which reduces computer run time. For the 1-10 MWe engine, the drop in efficiency at rated output is a common characteristic for a heavily loaded engine. It is beneficial to use such an engine for the central receiver system as the majority of the time the turbine is operating at less than its maximum rating.

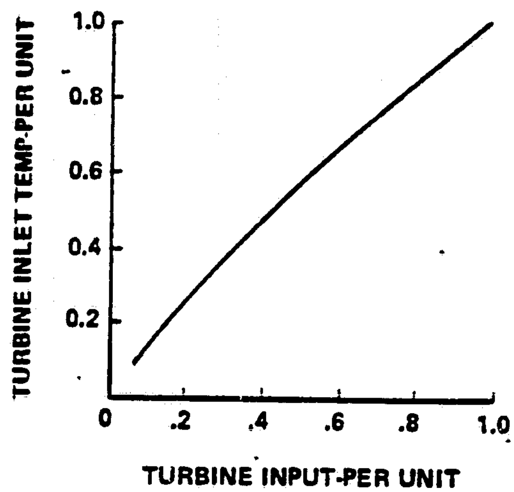

FIGURE 2-31. TURBINE INLET TEMPERATURE VS. TURBINE INPUT POWER

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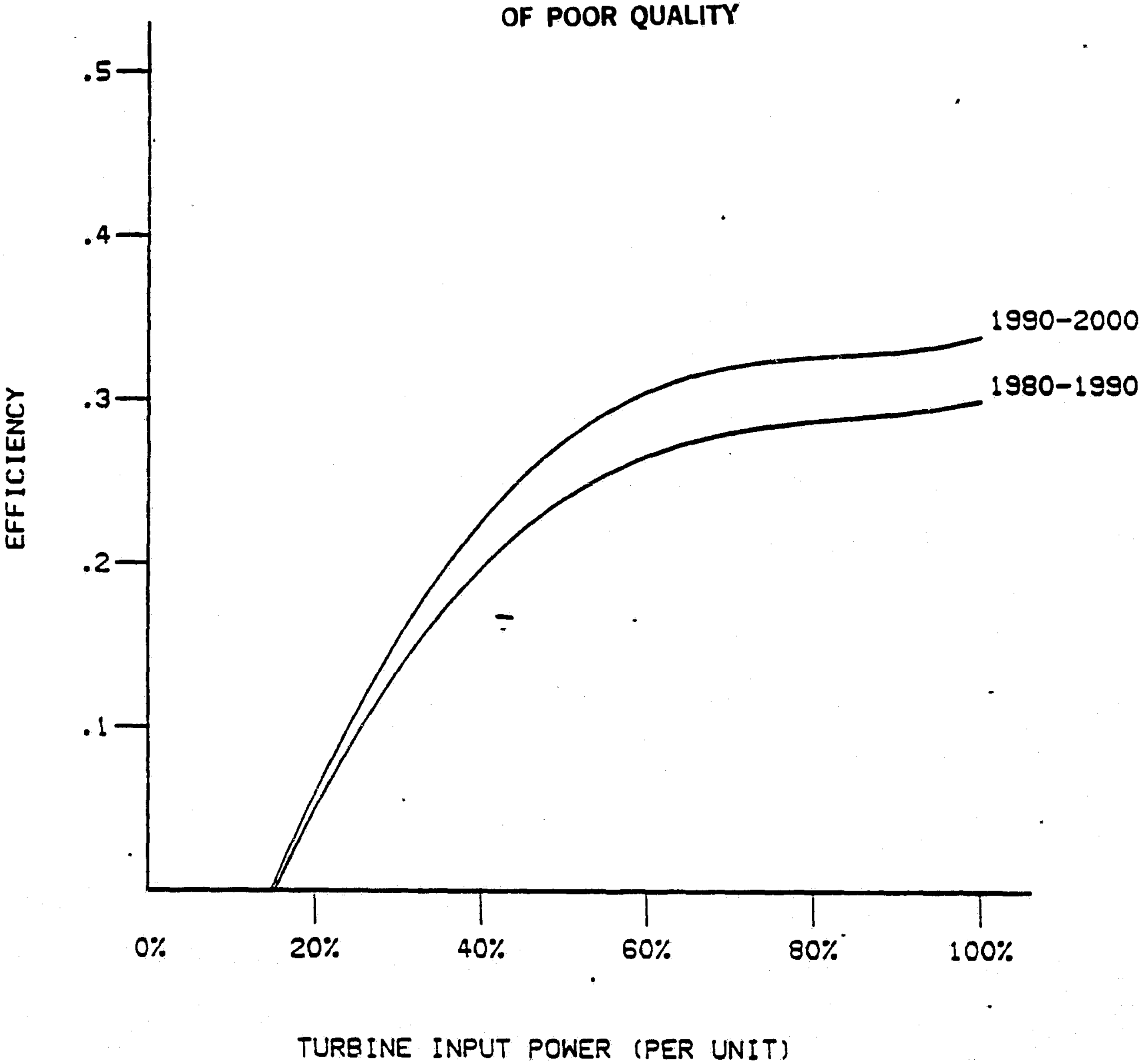

10-25 kWe - OPEN BRAYTON

FIGURE 2-32. Engine Efficiency vs. Power Input

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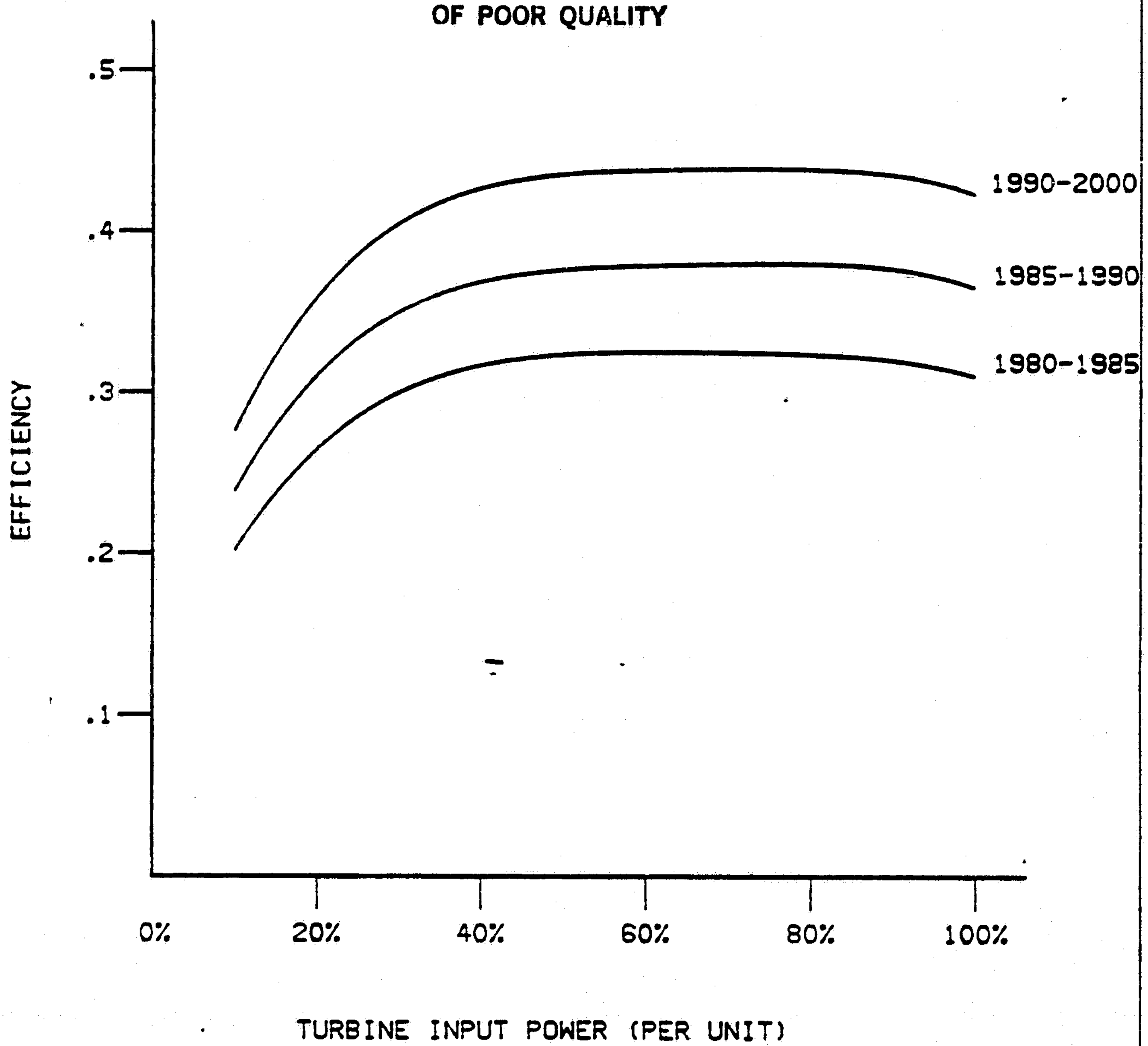


1-10 MWE - OPEN BRAYTON EFFICIENCY

FIGURE 2-33. Engine Efficiency vs. Power Input

The correction of engine efficiency for non-standard conditions uses the well-known correction term.

$$\eta = \eta_o \cdot \left[(1 - A\ (T - T_o) \cdot P/P_o\right]$$

where:

η = efficiency at Temperature T and Pressure P

η_o = efficiency at rated conditions ($T = T_o$, $P = P_o$)

T_o, P_o, = rated temperature and pressure, respectively

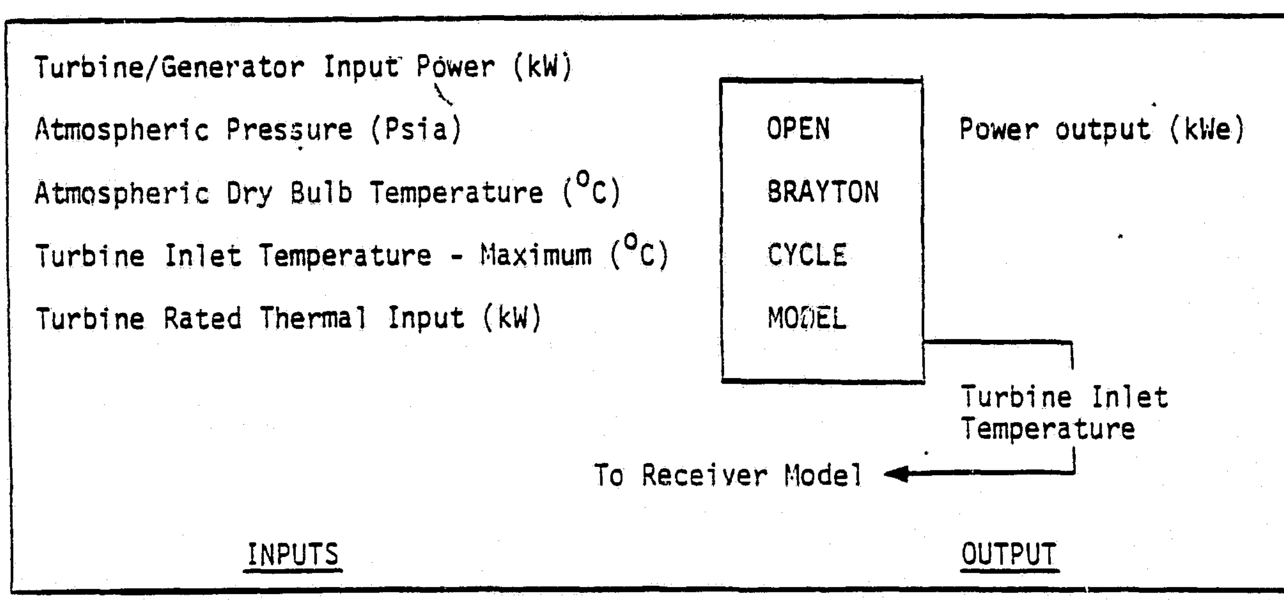
A = an empirical constant = 0.0072/°C used in modeling

The turbine inlet temperature (TIT)-turbine input power(TIP) relationship is determined experimentally for each engine. Examination of detailed empirical data on existing engines which should be representative of future engines to be modeled gave the relationship.

$$TIT = TIT_o \cdot (0.0363 + 1.171\ U - 0.2068\ U^2 + 0.00295\ U^3)$$

where: U is per unit power input to turbine.

The inputs and outputs to the Brayton cycle computer model are shown below.



Closed Brayton Cycle

A flow schematic of the closed Brayton cycle is shown on Figure 2-34, and a temperature-entropy diagram for the cycle is shown in Figure 2-30. The ideal closed Brayton cycle consists of the same thermodynamic processes as does the open cycle Brayton engine with the exception that the waste heat is rejected from the working fluid in a heat exchanger. The heat transfered into the circulating water is then rejected into the atmosphere by a cooling tower.

Cycle efficiency can be improved by the addition of a regenerator, shown by broken lines on Figure 2-34. As in the case of regenerative open Brayton cycle, this is accomplished by using some of the waste heat in the turbine exhaust to heat the compressor output. The waste heat recaptured reduces the external heat input to the system thus increasing the efficiency.

The selection of working fluid can be made from a variety of candidate fluids. Since turbine exhaust fluid is not expelled to the atmosphere, the choice is not limited to air. Initial studies have shown that the optimum working fluid for 1-10 MWe cycles is air and for extremely small capacity cycles the best choice is helium.

The method of load control is a significant feature of the closed Brayton cycle. Instead of modulating the turbine inlet temperature to control the power output, cycle pressure is regulated. Therefore, in the closed Brayton cycle, turbine inlet temperature remains constant and the working fluid mass flow rate varies.

Performance Projection

Closed cycle gas turbines, for various reasons, have not found as widespread use as open cycle turbines and therefore their development has been slow. Because closed Brayton cycle engines typical of those that would be used in the SPS program are not currently being produced, performance estimates must be based on current

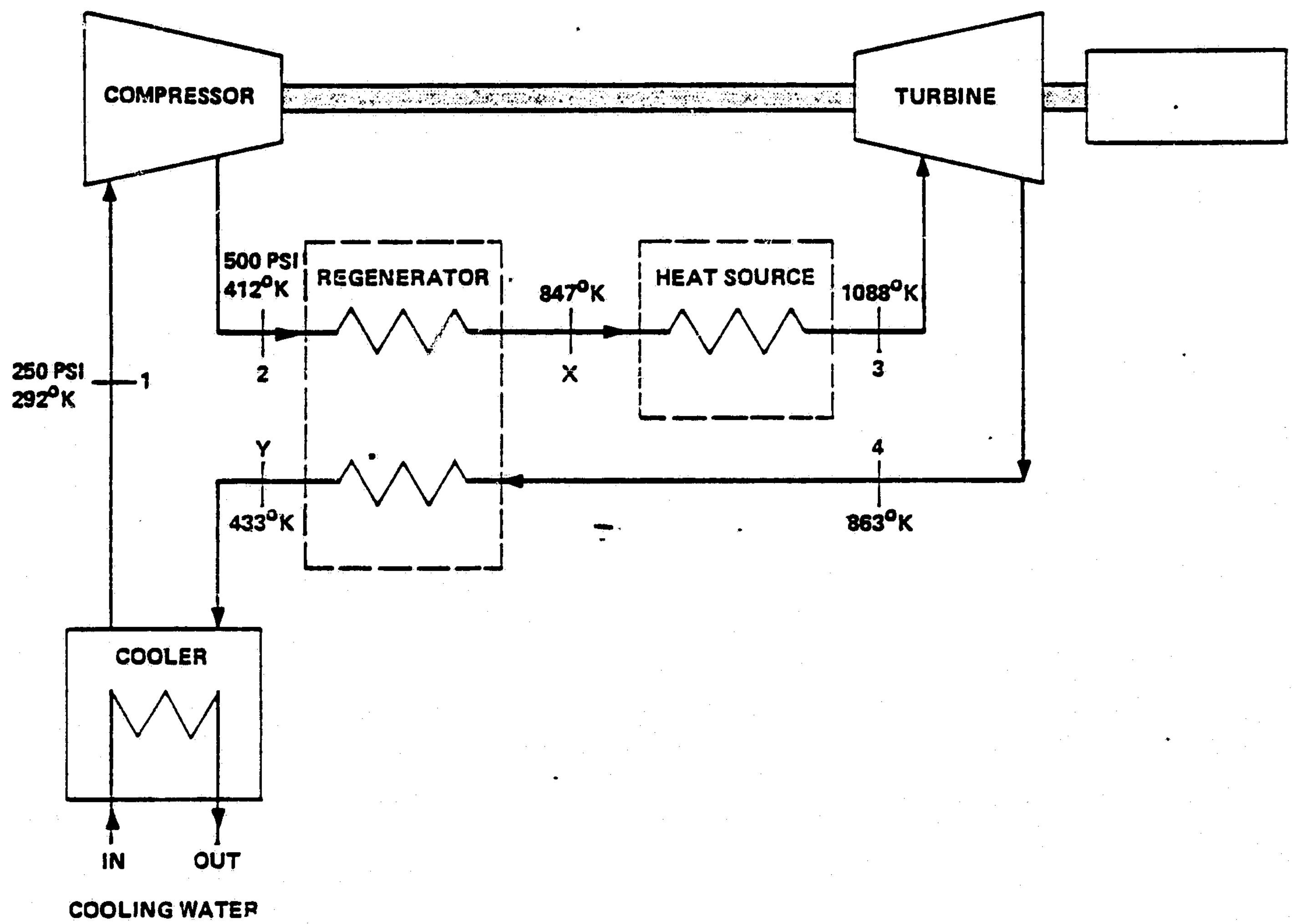


FIGURE 2-34. REGENERATIVE CLOSED BRAYTON CYCLE FLOW SCHEMATIC

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research and development projects. The leading firm doing such research is the Airesearch Manufacturing Company of the Garrett Corporation in Phoenix, Arizona. Airesearch has been involved in such programs over the past twenty years. Closed cycle engines do exist in Germany in sizes from 2.3 to 20 MWe; however, these machines are lower performance machines, 25-30 percent efficiency, with TIT's of 930°K (1210°F) to 980°K (1310°F). Further, they are designed as part of total energy systems and use coal, mine gas or blast furnace gas for fuel(36).

The Garrett data supplied to B&V represents engines which they believe could be available in 1984 and further estimated that continuous development encouraged by high volume production would allow improvements in cycle efficiency. For the 10-25 kWe machines the top efficiency is 32.4 percent for 1984 and 36.9 percent for 1990-1999. For the 1-10 MWe machine in 1984, the top efficiency is 38.5 percent and for the 1990-1999 time frame the top efficiency is 43.9 percent. AiResearch also supplied information on part load performance of these engines.

Component Availability

There are no production closed Brayton cycle engines available at the present time. A market pull established either by significant governmental funds or by development of a large market potential from studies such as the present one on SPS Impact Analysis should result in development of production units. If this occurs, a 6-12 month delivery schedule seems appropriate.

Cost Projections

Airesearch supplied the following estimates of costs for the closed Brayton cycle engines.

Size	Item	1984-1989	1990-1999	Remarks
10-15 kW_e	Capital Cost ($\$/kW_e$) O&M Cost ($/kWh)	320-- 0.015	160-- 0.015	Limited Production early period, mass production 1990-1999
1-10 MWe	Capital Cost ($\$/kW_e$) O&M Cost ($/kWh)	- 0.006	160-- 0.006	The mature production cost appears low compared to current open cycle machines.

Performance Modeling

Modeling of the closed Brayton cycle machinery follows a similar procedure to that used for the open cycle engine. The main change is that the load matching of the closed Brayton cycle is not dependent on atmospheric pressure.

The overall performance of the closed Brayton cycle engine is given in Figures 2-35 and 2-36 for the 10-25 kW_e and the 1-10 MW_e units respectively.

The inputs and outputs for the model are listed below.

INPUTS		OUTPUT
Turbine/Generator Input Power (kW)	OPEN	Power Output (kWe)
Atmospheric Dry Bulb Temperature (^{o}C)	BRAYTON	
Turbine Inlet Temperature - Maximum (^{o}C)	CYCLE	
Turbine Rated Thermal Input (kW)	MODEL	

Stirling Cycle

A schematic of an engine operating on the Stirling cycle is shown in Figure 2-37. The four thermodynamic processes that comprise the Stirling cycle are illustrated on the temperature-entropy diagram of Figure 2-38. In the first process, the compressor piston isothermally compresses the working fluid from state 1 to state 2. The working fluid then flows from its compressor cylinder through the regenerator into the power piston. In this process, the working fluid undergoes constant

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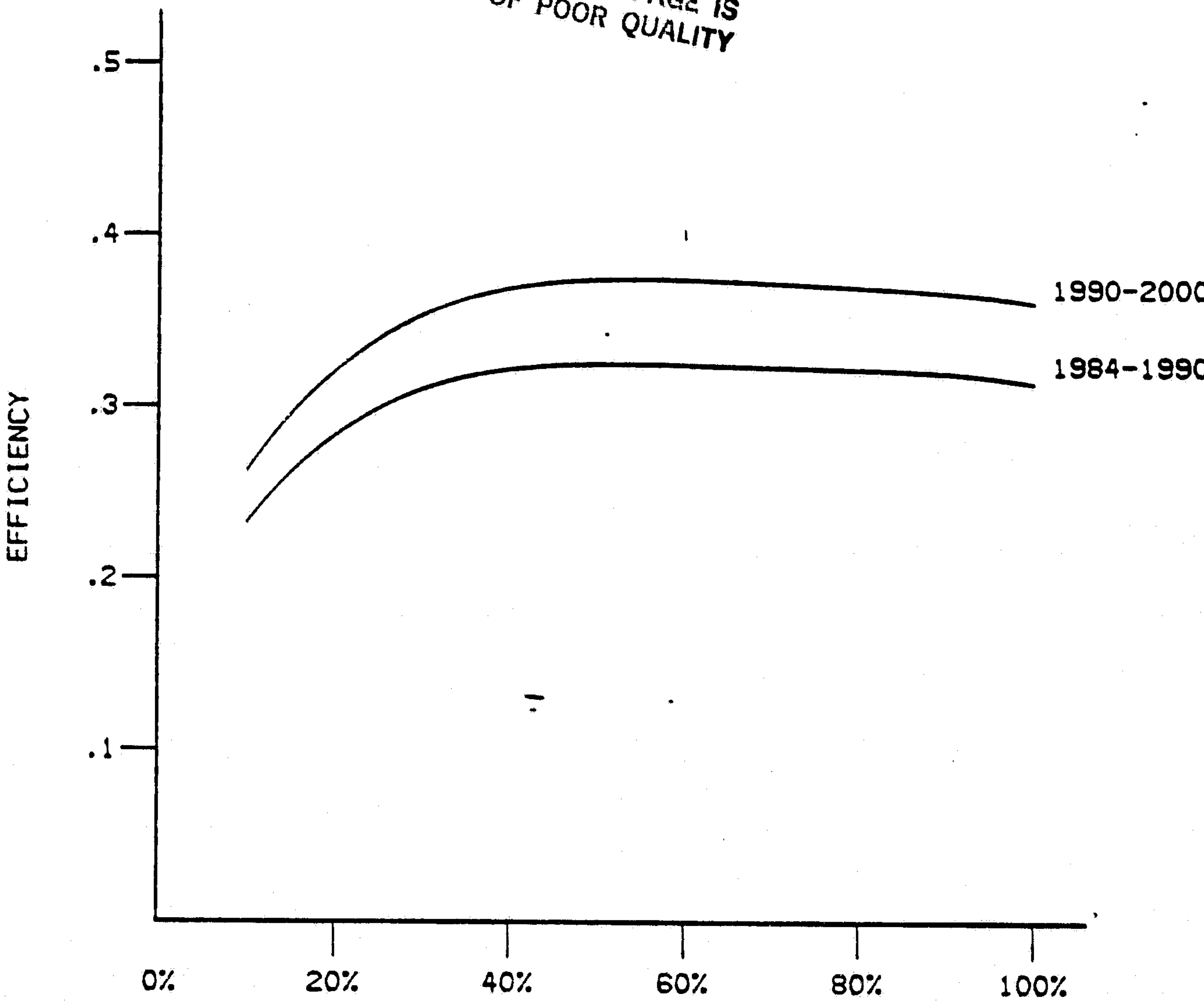

10-25 kWe - CLOSED BRAYTON

FIGURE 2-35. Engine Efficiency vs. Power Input

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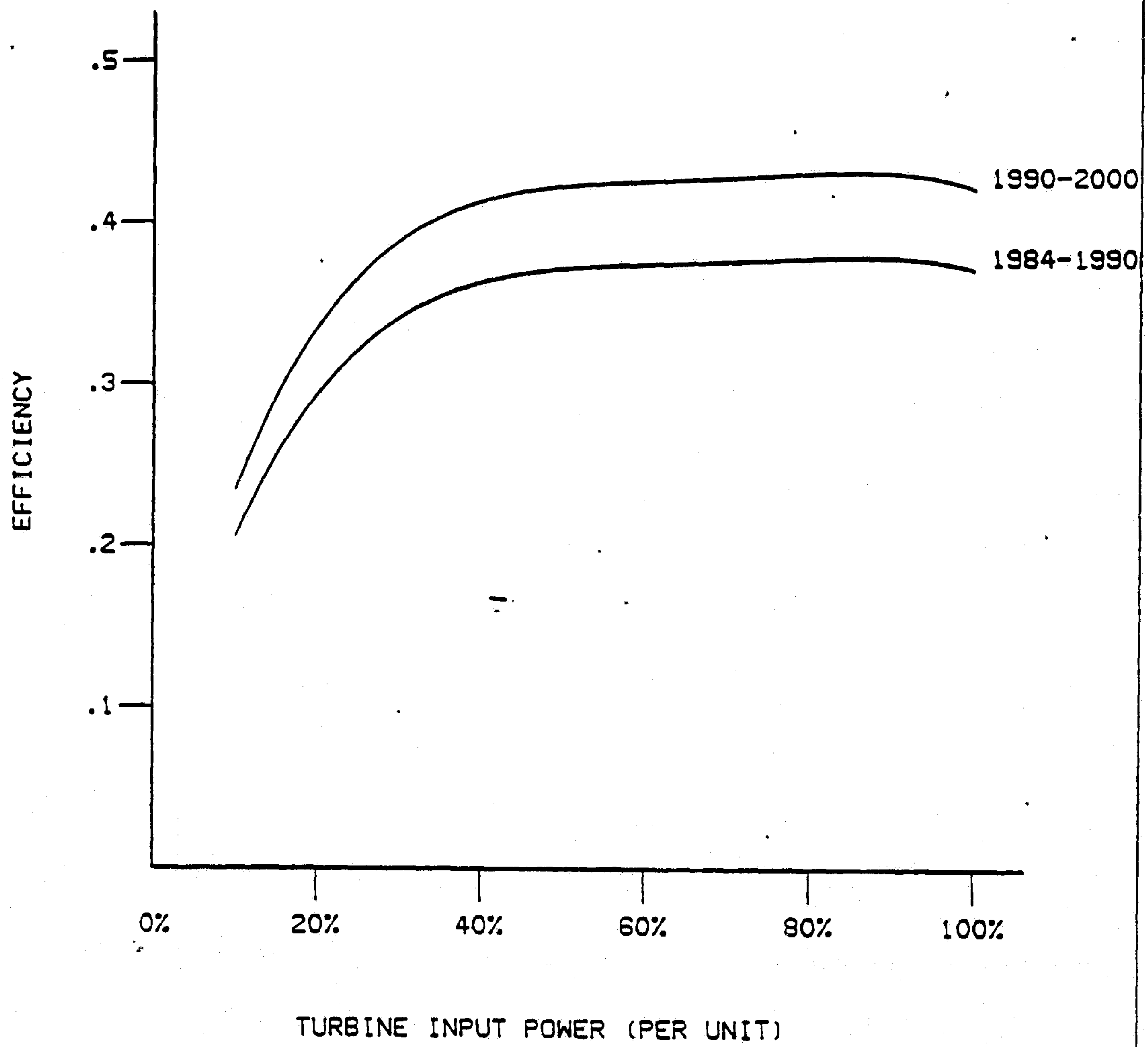

1-10 MWE - CLOSED BRAYTON

FIGURE 2-36. Engine Efficiency vs. Power Input

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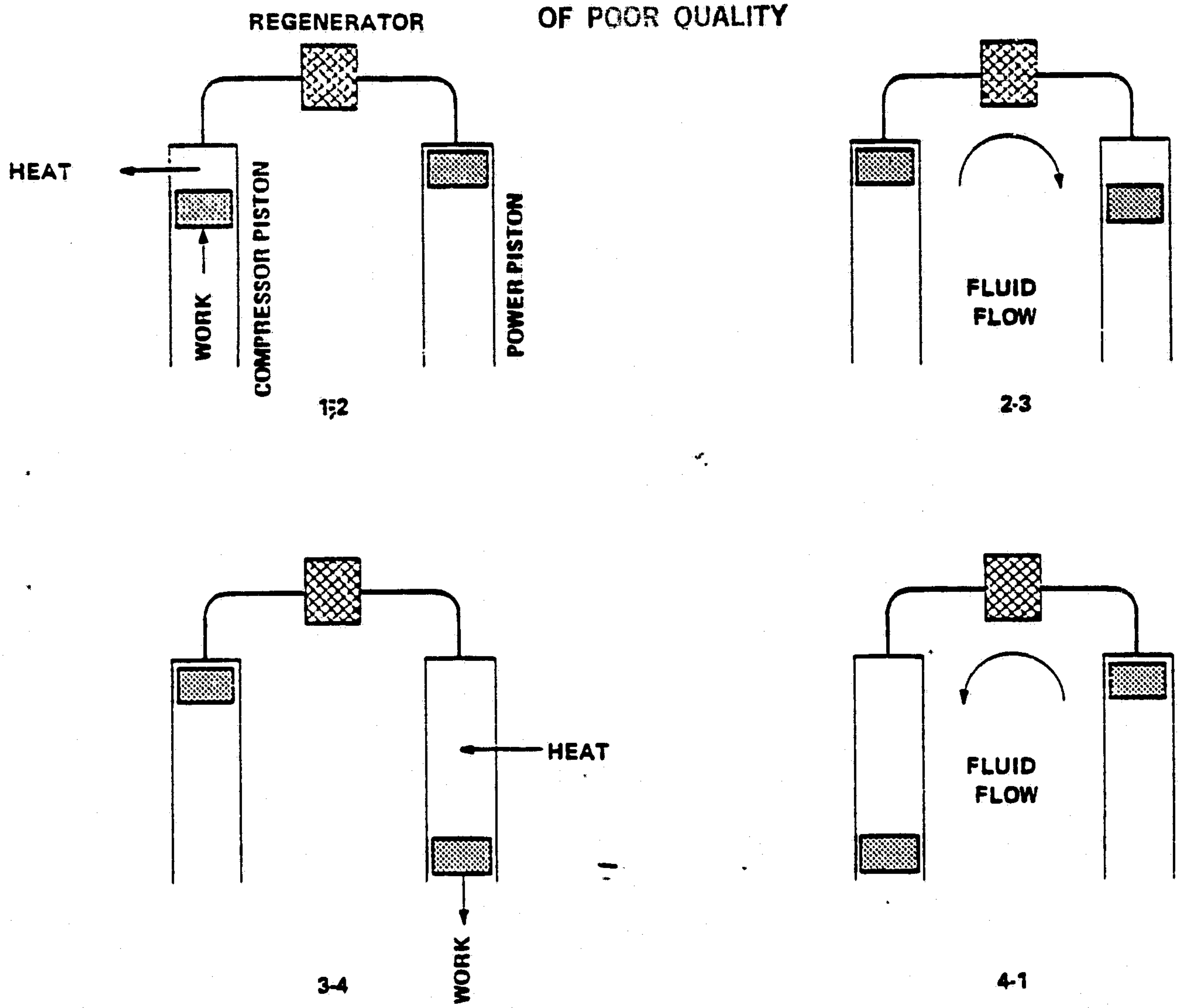

1-2 ISOTHERMAL COMPRESSION
2-3 CONSTANT VOLUME REGENERATIVE HEATING
3-4 ISOTHERMAL EXPANSION
4-1 CONSTANT VOLUME REGENERATIVE COOLING

FIGURE 2-37. The Ideal Stirling Cycle

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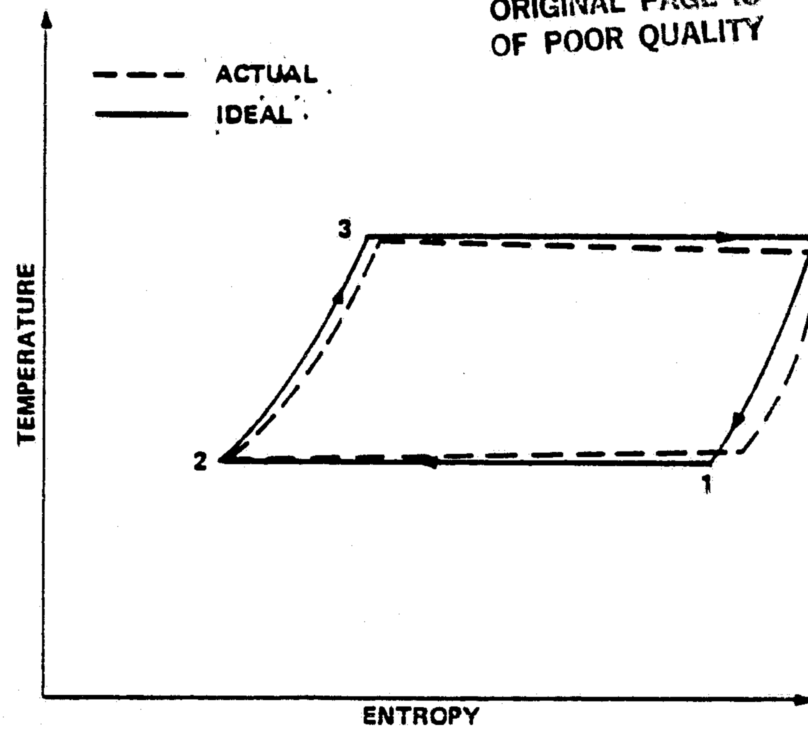

FIGURE 2-38. Stirling Cycle T-S Diagram

volume heating by the regenerator from state 2 to 3. Next, thermal energy is added to the working fluid, causing it to isothermally expand from state 3 to 4. In the expansion, the power piston is forced out of the cylinder thus doing work. The final thermodynamic process occurs when the power piston forces the working fluid back through the regenerator into the compressor cylinder. In this constant volume process, the working fluid transfers heat to the regenerator as it cools from state 4 to state 1.

The working fluid used in the Stirling cycle is a gas; air, helium and hydrogen are common choices of the working fluid. There are two primary types of Stirling engines: the kinematic engine which has been fostered by Philips and United Stirling and the free piston engine advocated by ERG, MTI, and Sunpower. These two types of engines are named in accord with the means they use to move the two pistons in the appropriate phase relationship. The kinematic uses a series of linkages, the free piston uses the natural frequency of oscillation of a freely moving piston with an air spring at one end.

For this program, the examination of the alternate engines, discussions with the key research and development people, and its potential

availability led us to choose the free piston engine for modeling. The desirability of the Stirling engine is that its theoretical efficiency is equal to the Carnot efficiency. The difficulty has been effectively meeting the stringent temperature requirements and accomplishing the isothermal compression and expansion.

Performance Projection

The data base for predicting performance of Stirling engines is lacking in two ways. First no engine in the 10-25 kW size has been built. Second, performance data that do exist for other size engines do not support a highly reliable extrapolation of design performance to actual performance. The MTI data[37] on actural performance compared to design performance values illustrate this problem, Table 2-8.

TABLE 2-8. MTI Stirling Engine Results

Model Number	Power (kW) Design	Power (kW) Actual	Efficiency Design	Efficiency Actual	Remarks
FPSG-005-1	1.00	0.67	0.32	0.27	Engine
HCVa	1.6	1.6	0.32	0.29	Engine
HCV6	1.6	2.0	0.32	0.32	Engine
FPSG-010-2	1.3/1.0	1.3/.97	0.36/0.25	0.33/0.19	Engine/System

The ratio of actual performance to design performance varies from 0.67 to 1.25 for power output and from 0.76 to 1.00 for efficiency. Furthermore, data supplied by MTI on efficiency vs stroke has significant scatter, correlation coeficient of 0.2 for system efficiency vs stroke and 0.38 for engine efficiency vs stroke. The standard deviation of the engine efficiency is 1.76 percent and its mean value is 29.76 percent. MTI provided B&V actual data on engine efficiency vs engine thermal input which is used as a basis for the engine performance. The actual values supplied by MTI were adjusted upward by 7 percent for 1988 usage to temper the present low values with design goal values. The estimate of efficiency for Stirling engines is, at best, a soft number. For the

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1993-1999 time frame a further improvement (7 percent) above the 1988-1992 values is estimated.

Component Availability

There are no Stirling engines commercially produced at the present time. Currently DOE is funding General Electric Company, United Stirling, MTI and ERG Inc. on Stirling engine development. The first bench tests of the advanced engines (MTI and ERG) have a planned test schedule for FY 1983[38].

Cost Projections

Discussions with MTI[40], provided an estimate for capital cost of Stirling engines of $163/kW and an O&M cost of $0.02/kWh. These values are based on mass production quantities of a level of 25,000 engines per year.

Performance Modeling

The performance modeling of the Stirling engine empirically matches a convenient algorithm to the engine efficiency data supplied by MTI. This efficiency is adjusted for changes in atmospheric ambient temperature by a multiplicative correction term.

$$\eta = \eta_o \left[1-(T-T_o) \times 0.00072\right]$$

where

η = engine efficiency
η_o = engine efficiency at the reference temperature T_o
T = ambient air temperature in ^oC
T_o = design value of ambient temperature

The assumption in the model of the Stirling engine is that the operating temperature of the unit is kept constant so that the efficiency of conversion is at its largest value. The data points for the experimentally

determined efficiency are shown in Table 2-9. The linear generator efficiency that MTI believes can be achieved is 0.91. The actual system efficiency at rated power is 0.91 x 0.290 = 0.264, which still does not include auxiliary power needed for heat rejection fans, collector drives, etc. Thus, the data in Table 2-9 was increased by 10 percent and then 3 percent was allocated for auxillary power. The resultant net efficiency vs per unit input power is shown in Figure 2-39.

TABLE 2-9. MTI STIRLING ENGINE PERFORMANCE*

Stroke cm	Pin kW	Pout kW	
1.0	1.56	0.28	0.18
1.5	2.05	0.55	0.268
2.0	2.70	0.80	0.296
2.5	4.03	1.20	0.298
3.0	5.10	1.48	0.290

*FPSG-010-1 engine, design pressure 80 bar, design temperature 650°C (1200 F), generator efficiency not included.

The inputs for the Stirling engine are the same as for the closed Brayton Cycle and are shown below.

INPUTS		OUTPUT
Engine/generator Input Power (kW)	STIRLING	
Atmospheric dry bulb Temperature (°C)	ENGINE	Power Output (kW)
Engine Operating Temerature (°C)	CYCLE	
Engine rate Thermal Input (kW)	MODEL	

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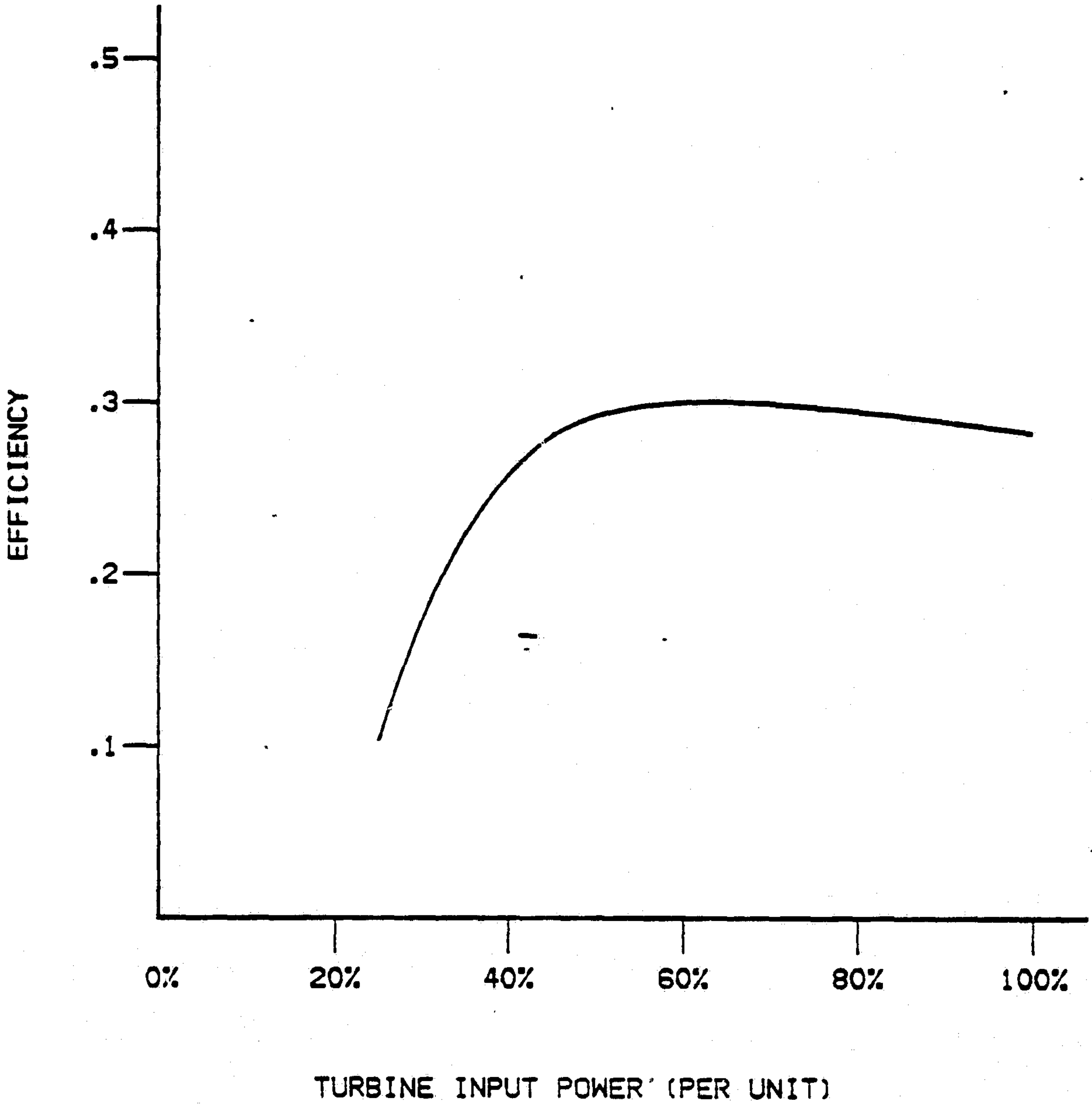

STIRLING ENGINE

FIGURE 2-39. Engine Efficiency vs. Power Input

Rankine Cycle

The Rankine cycle, the most commonly used thermodynamic cycle for electric power generation, is shown in Figures 2-40 and 2-41 As shown, the cycle is a five step process. The working fluid changes state from liquid to gas to liquid for non-supercritical cycles. It is compressed to high pressure by feedwater pumps from state 1 to state 2. From state 2, heat is added to the working fluid in the solar receiver or by an external fossil fuel source preheating, vaporizing, and superheating the fluid to state 3. The fluid is throttled, 3-4, and then expanded through the engine which converts the thermal energy into mechanical form and drives the generator, 4 to 5. Waste turbine exhaust heat is rejected from the working fluid in the condenser where it returns to a liquid, state 1. The heavy line in Figure 2-41 shows the T-S diagram boundaries between the liquid and gaseous states of the working fluid. For supercritical cycles the state points, 2,3, and 4 are above the "dome" and there is no isothermal vaporization step.

The use of feedwater heaters in a regenerative Rankine cycle is the primary cycle variation. The regenerative Rankine cycle is shown by dashed lines in Figure 2-40 and 2-41. In the feedwater heaters, heat from steam extracted from the turbine is transferred to feedwater. The net effect is to raise the average temperature at which heat is added to the working fluid, thus improving cycle efficiency. The number of feedwater heaters used depends on the size of the plant.

A second major cycle variation, not shown in the figures nor considered in the model, is the reheat cycle. In this variation, the working fluid is partially expanded, reheated to a higher temperature, and then expanded again. This concept also improves cycle efficiency.

Although water/steam is the most common working fluid used in the Rankine Cycle, other fluids can be used. For example, toluene is used in an organic Rankine Cycle in small power rating applications.

The water/steam requires careful maintenance of the water quality to prevent excessive corrosion and mineral build-up on components.

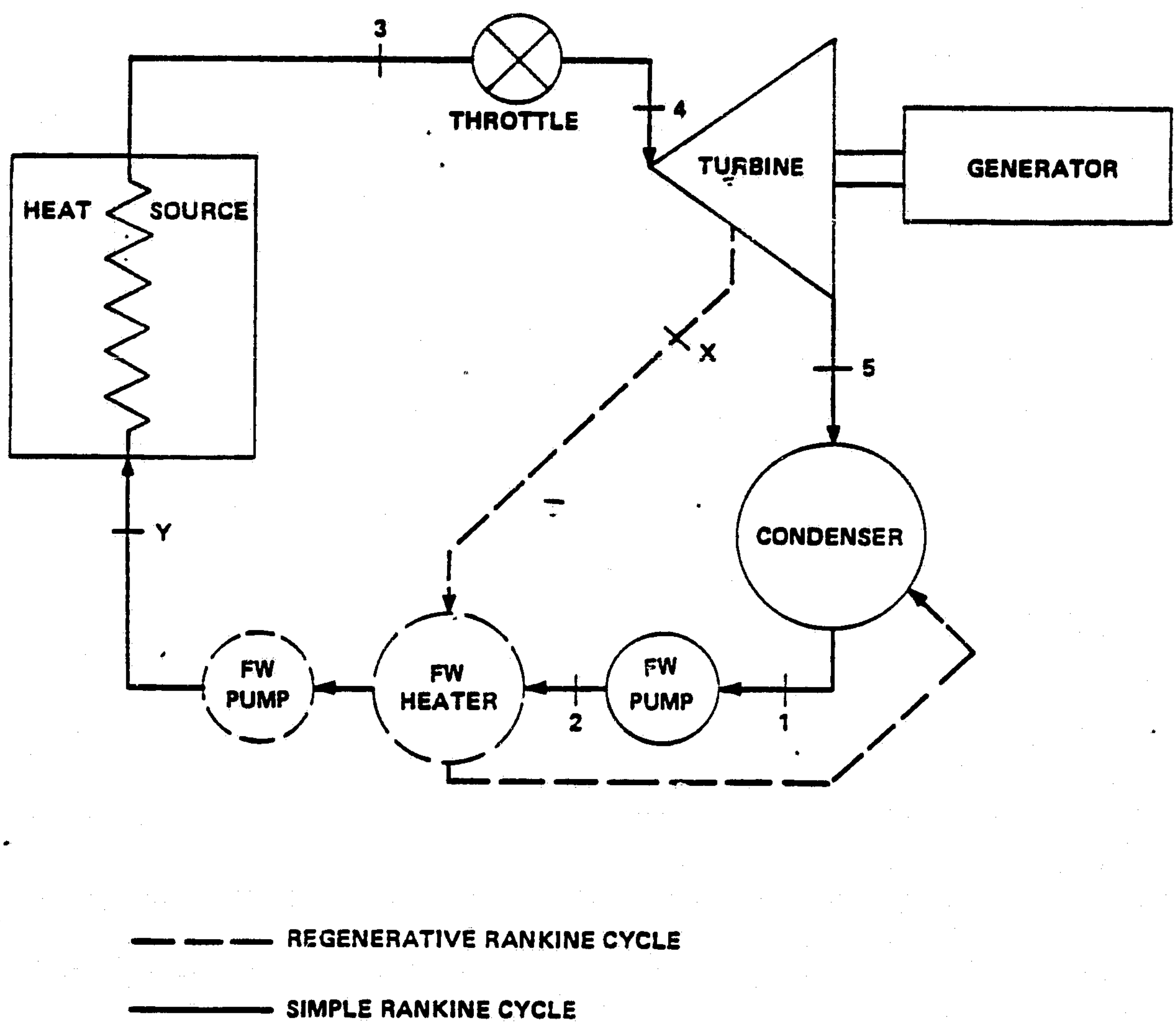

FIGURE 2-40. Regenerative Rankine Cycle Flow Schematic

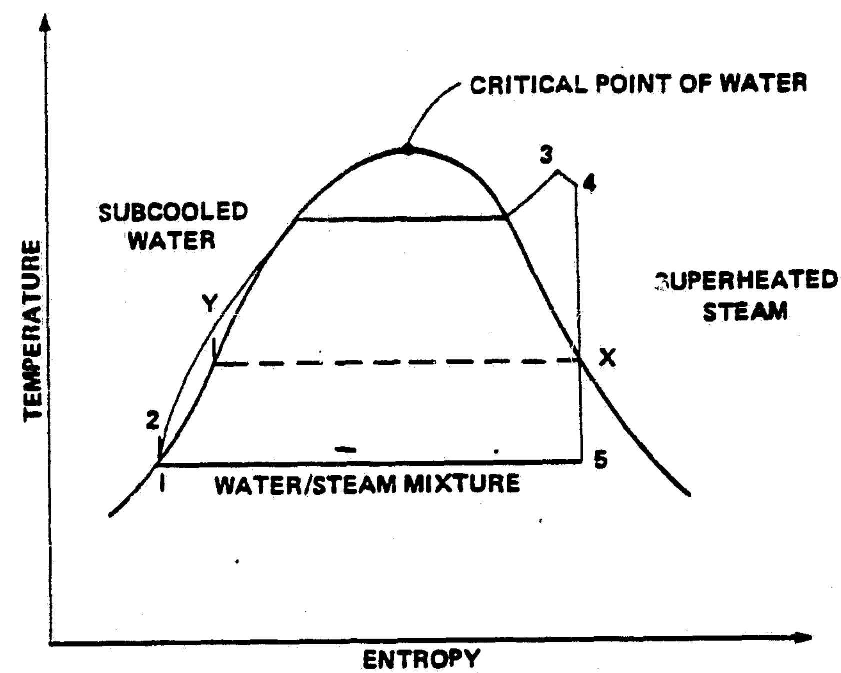

FIGURE 2-41. Regenerative Rankine Cycle T-S Diagram (Steam Cycle)

The conversion of thermal energy into mechanical energy in the expansion portion of the cycle can be accomplished by many different engine designs, viz. turbine, piston, screw expanders, and vane exapnders. For the SPS project, we have selected a General Electric steam turbine with two stages of regenerative feedwater heaters for the 1-10 MWe size units. A Sundstrand toluene turbine with one stage of regenerative heating was selected for the 4-22 kWe size unit to be used with a dish collector. This selection is based on the expected reliability, performance, operating conditions, and costs of these units. Moreover, the single reheat design of the 4-22 kWe Sundstrand machine is unique; reheat for steam turbines in power plants is not used in commercial units below 60 MWe capacity because it has not been shown to be cost effective. Foster Wheeler/AFI Energy Systems also manufacturers organic Rankine turbines up to several MW.

Performance Projections

Manufacturers solicited for future performance information on 10-25 kWe engines provided no firm specifications. Effort therefore centered upon estimates of engine modifications which may lead to improved performance. Factors of the EPGS (electric power generation system) that can be improved to increase the performance of the cycle are as follows:

1. Aerodynamic performance of the turbine
2. Electrical efficiency
3. Mechanical efficiency of the gearbox (if applicable)
4. Thermodynamic performance due to initial temperature and pressure or condenser saturation pressure.
5. Performance due to improvements in the cycle arrangement.

Improvements in efficiency due to items 1 and 2 would be very slight or nonexistent, as Sunstrand has tried to develop the most efficient machine for the application. Items 3 and 5 offer no potential. A one to two percent improvement, not percentage points, is estimated by 2000, due to new developments in blading, closer seal clearances, and better generator conductor design and cooling. Item 4 depends largely on the working fluid and its maximum attainable working conditions from a reliability standpoint. Sundstrand's turbine uses toluene, which

appears to be the best organic fluid available today, at its maximum temperature. The assumption of a new working fluid is included in the estimate of future performance.

The 1-10 MWe steam Rankine Cycle is based on a General Electric single-flow non-reheat condensing turbine. The cycle description and last stage blade size is given in Table 2-10. This cycle is used as an illustration to our modeling approach.

TABLE 2-10. 1-10 MWe SPS Data

Rating (MWe)	Last Stage Blade Size (in)	Number of FW Heaters
1	.6.1	3
5	7.2	3
10	10.0	4

General Electric small turbine department projected performance improvements of 11 percent for the time frame 1990 and beyond. In the analyses performed, cost versus wet cooling was examined for the 1-10 MW units. A cost/effectiveness figure of merit showed that the lower cost and auxiliary power for dry cooling systems offset the increased collector cost needed to compensate for their lower performance. The dry cooling system was modeled.

Component Availability

Rankine cycle engine technology is well developed, thus component availability is not limited by technology. The manufacture of future higher performance turbines will be controlled by market volume.

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A sampling of manufacturers with current production of Rankine cycle engines pertinent to the SPS project is given in Table 2-11. Delivery time for 10-25 kWe units is 12-18 months; for 1-10 MWe units 18-24 months..

TABLE 2-11. Some Available Rankine Cycle Heat Engines

MANUFACTURER	RATING	REMARKS
CARLING TURBINE BLOWER CO.	100 KW	
COPPUS ENGINEERING CORP.	3 KW	
	5 KW	
	10 KW	
	20 KW	
	100 KW	
	400 KW	
GENERAL ELECTRIC CO.	1-10 MW	
ELLIOT TURBOMACHINERY	65 KW	ISOBUTANE, USED IN REFINERIES
ORMAT TURBINES, LTD (ISRAEL)	N/A	SMALL, HIGH RELIABILITY
TERRY STEAM TURBINE INC.	2 KW	
	10 KW	
	100 KW	
	1,000 KW	
TRANE CO. (MURRAY TURBINES)	250 KW	
TURBODYNE DIVISION/WORTHINGTON PUMP CORP.	500 KW 1,000 KW	
THERMO-ELECTRON	3 KW 44 HP 104 KW 1,000 KW	FLUORINOL, USED IN REFINERIES
WESTINGHOUSE	10 MW	
SUNSTRAND	36 KW	TOLUENE-NOT IN PRODUCTION
	600 KW 100 KW	STEAM

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Cost Projections

Budget cost estimates from vendors resulted in the following nominal cost values for 1-10 MWe units.

Rating (MWe)	Cost ($/kWe)
1	1400
5	700
10	400

For the 10-25 kWe Sundstrand Corporation projected the following capital costs:

Unit Size	Production Rate (units/year)	
	10^4/yr	10^5/yr
22kW	$637/kW	$307/kW
50kW	$330/kW	$160/kW

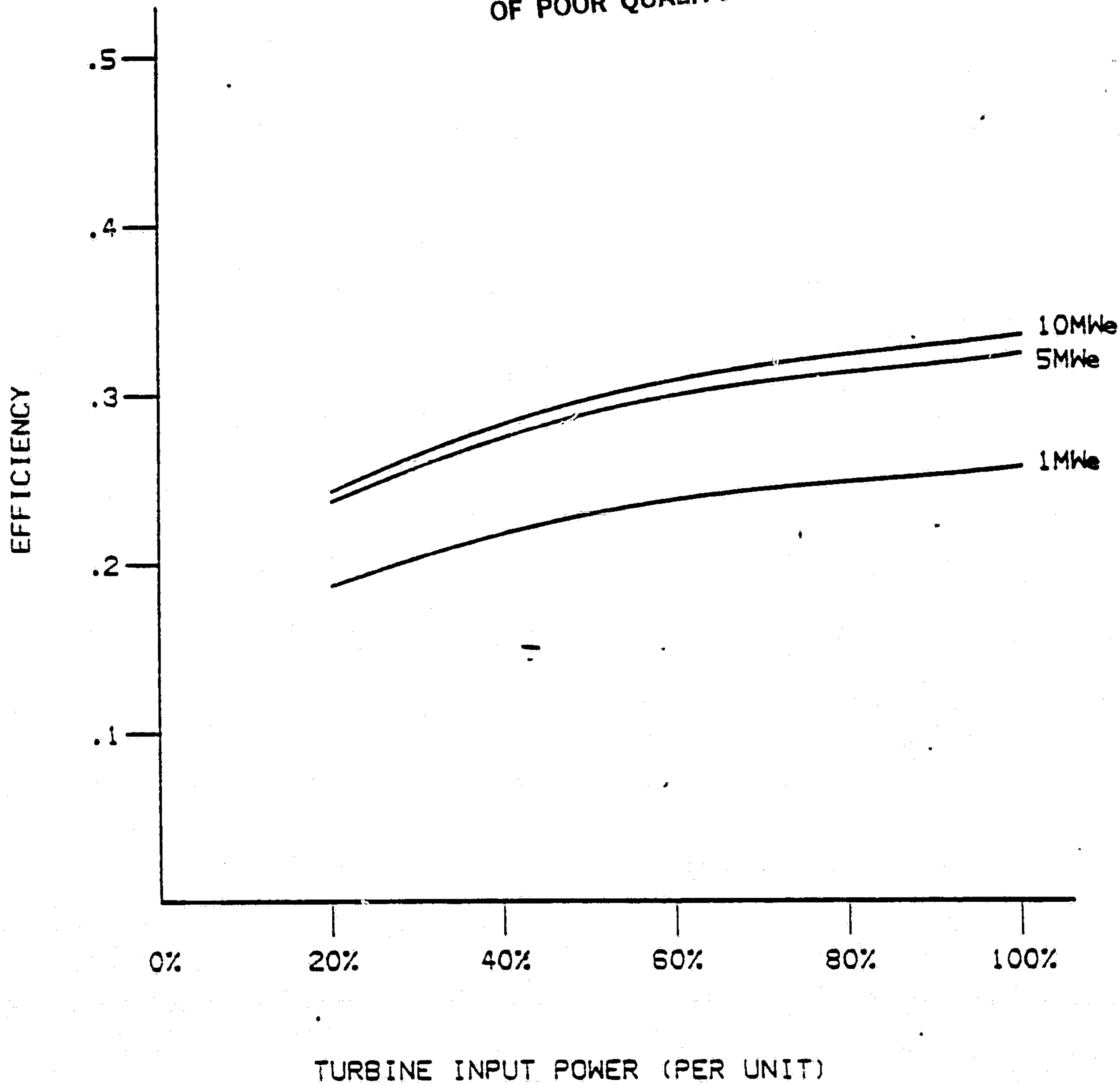
Performance Method

The performance models for the 1-10 MW steam turbine have been developed from actual data on the G.E. turbines. The rated net cycle efficiency is related to turbine size (maximum power rating). This in turn was converted into an algorithm for turbine efficiency as a function of turbine input power, see Figure 2-42. The overall cycle efficiency including generator losses is then adjusted to reflect the auxiliary load requirements for the cycle. Thus the system efficiency, η ,is

$$\eta = \eta_c \left(\frac{P_{in}\,\eta_c - P_{aux}}{P_{in}\,\eta_c} \right)$$

where η_c = cycle efficiency

P_{in} = power input to the cycle



1-10MWe STEAM RANKINE CYCLE
EFFICIENCY

FIGURE 2-42. Engine Efficiency vs. Power Input

P_{aux} = auxiliary power

The auxiliary power for a plant with dry cooling is about 11 percent of the gross output at rated power and drops to 8 percent at zero net output. Thus

$$\eta = \eta_c(1 - 0.08 + 0.03\ P_{in}/P_{ino})$$

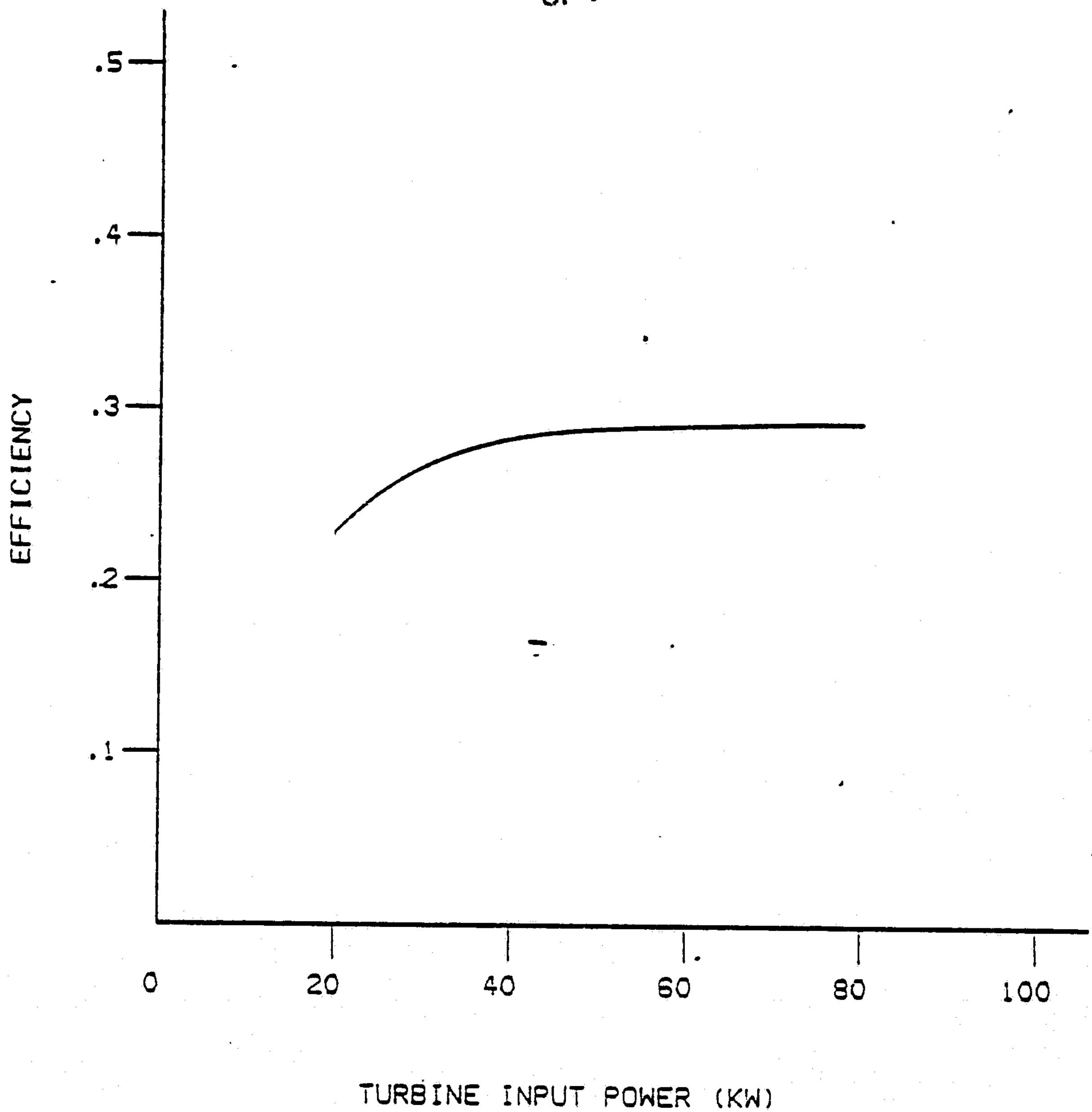
where P_{ino} is the rated power input to the cycle.

The adjustment to the turbine efficiency for ambient air temperature was assumed to be in proportion to the ratio of Carnot efficiency at off-design conditions.

Performance of the 10-25 kWe Rankine Cycle System uses a slightly different approach for modeling because the engine characteristics vary. In this case, a variable speed single stage impulse turbine design is used. The variable speed means that the turbine volumetric flow fluctuates with throttle conditions so that the resultant velocity relationships on the blades can be assumed to be similar. Therefore, machine performance can be modeled as a function of power input to the turbine. The relationship between input power and the cycle efficiency based on the Sundstrand machine is shown in Figure 2-43. Corrections are again needed for auxiliary power and ambient temperature. The auxiliary power is 7 percent of which 3 percent varies in proportion to per unit thermal input. The ambient temperature correction follows the Carnot efficiency.

Combined Cycle 1

The concept of combined cycle equipment is to utilize the exhaust thermal energy from one heat engine to supply the thermal input to a second, lower-temperature engine and thus increase the utilization of the heat into the first cycle. The higher temperature cycle is usually called the topping cycle or topper, and the lower temperature cycle is referred to as the bottomer. The only combined cycle considered for the



4-22 KWe TOLUENE RANKINE ENGINE

FIGURE 2-43. Engine Efficiency vs. Power Input

SPS is in the 1-10 MWe range. For a Brayton topper, and a steam Rankine bottomer, a central receiver collector configuration appears reasonable.

A schematic flow diagram for a combined cycle is given in Figure 2-44. The thermodynamic cycles are shown in Figure 2-45. As shown, two thermodynamic cycles are utilized for electric power generation. An open Brayton cycle is used as the topping cycle and a Rankine cycle is used as the bottoming cycle.

The open Brayton cycle topper essentially consists of the thermodynamic processes described earlier but with an exhaust temperature above the required operating temperature of the bottomer shown by the dashed lines.

A number of cycle variations exist for a combined cycle plant. The most prominent of these are:

- Reheat Rankine cycle.
- Regenerative Rankine cycle.
- Two-shaft gas turbine.

It should be pointed out, however, that the combined cycle is a complex cycle to control and operate; additional cycle complexities place further demands on the control system and operation of the system.

The part load performance of the combined cycle is poor, see Figure 2-46, and its use in a solar only mode without hybrid operation is probably not warranted.

Performance Projection

The performance projection for the combined cycle is based on engineering improvements applied to the Solar Division of International Harvester Company commercially available combined cycle. Discussions with Solar provided rated output efficiencies of 36 percent in the 1985-1989 period and 41 percent for the 1990-1999 period.

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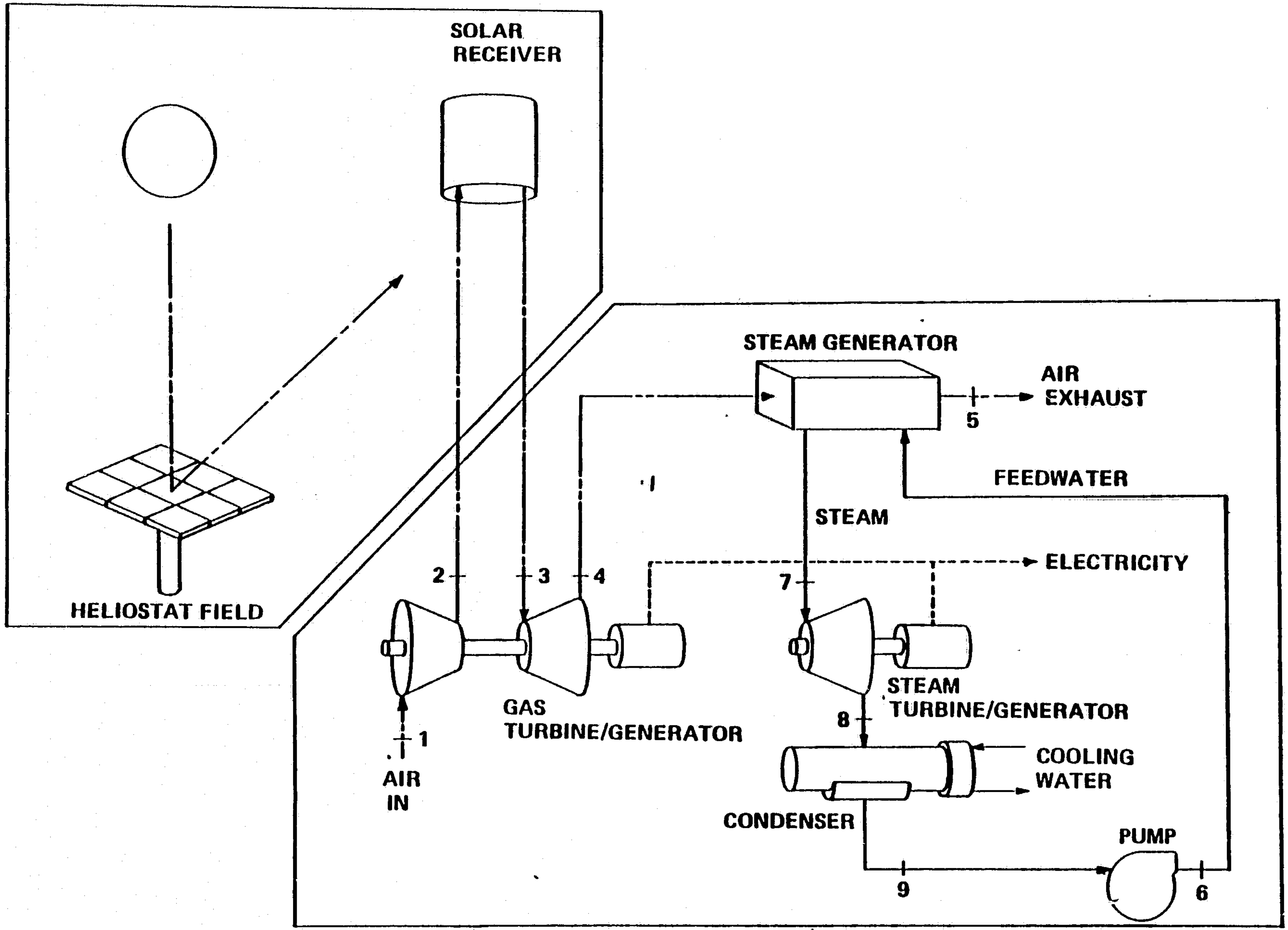

FIGURE 2-44. Combined Cycle Flow Schematic

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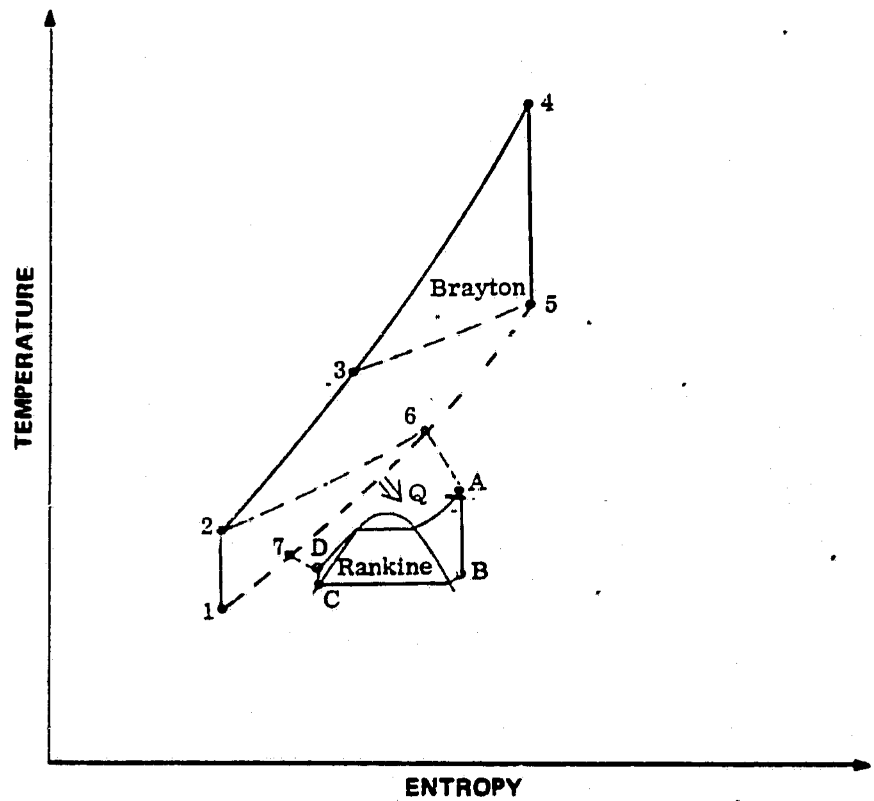

FIGURE 2-45. Combined Cycle T-S Diagram

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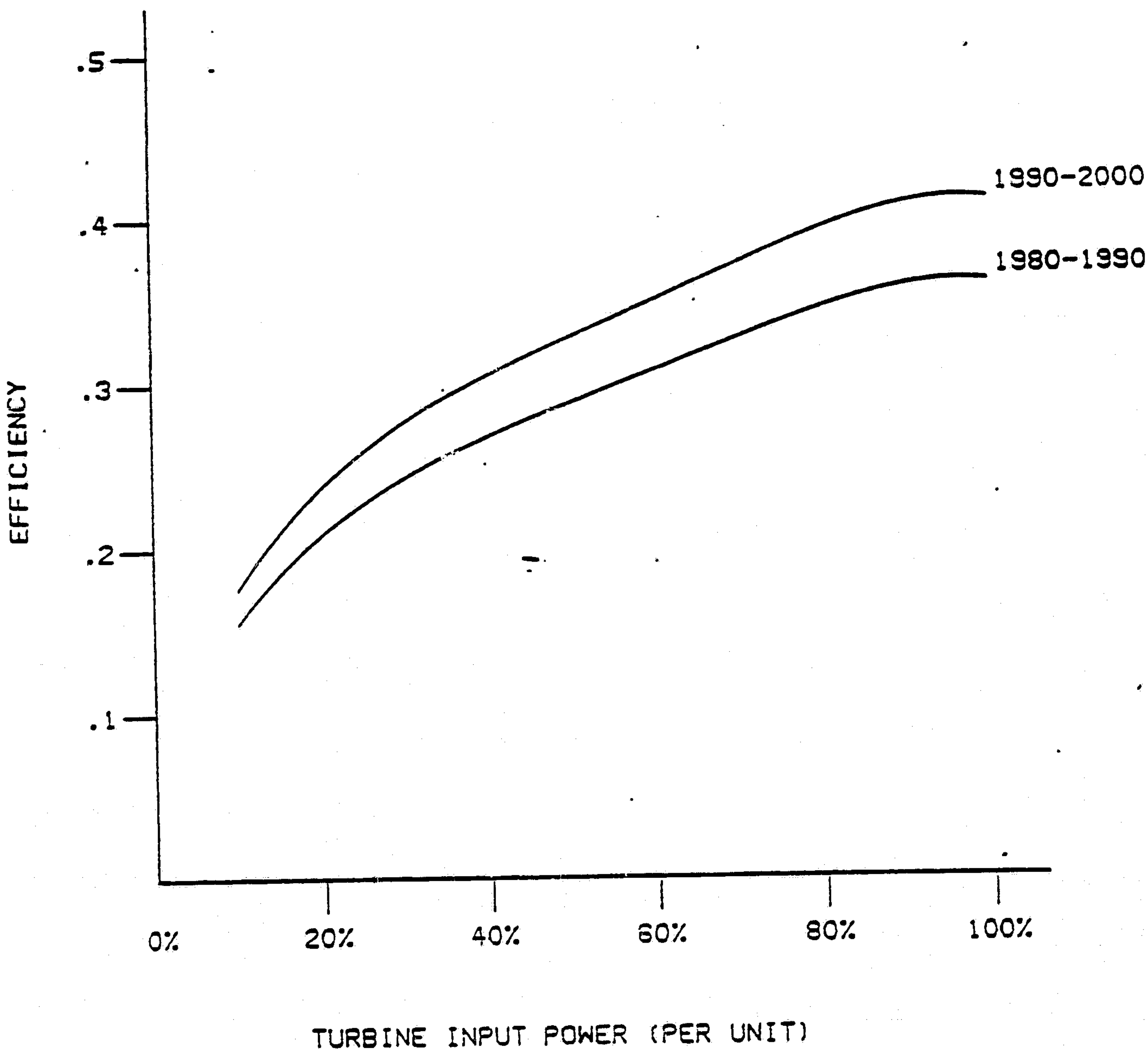

1-10 MWe - Combined Cycles

FIGURE 2-46. Engine Efficiency vs. Power Input

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Component Availability

Commercial availability of combined cycle units is indicated in Table 2-12. Delivery schedule for both manufacturers is 8-18 months.

TABLE 2-12. Combined Cycle Unit Availability

Manufacturer	Model #	Rating
International Harvestor/Solar	Centaur CC Mars CC	4,200 kW 10,500 kW
Sulzer	Turbatur 203 205 210	 3,530 kW 4,800 kW 9,700

Cost Projections

Vendor budget estimates for the combined cycle units are $400 per kW.

Performance Modeling

The performance modeling of the combined cycle is based on the Solar Centaur unit. Part load performance is shown in Figure 2-46. Corrections for ambient atmospheric conditions include adjustments for the atmospheric pressure corresponding to the Brayton cycle and the dry bulb temperature correction term. The modeling follows the same procedures used for the Brayton and the Rankine cycle.

2.2.6 Storage, Hybrid, and Balance of Plant

The performance/cost modeling of thermal storage, electrical storage, and hybrid subsystems is described in this section, as well as the overall storage/hybrid dispatch strategies which are being implemented. In addition, balance of plant considerations such as piping losses and costs are treated here because they are modeled in the same subroutine QAGOT as storage/hybrid.

Storage and hybrid generation both increase system flexibility by providing for electric output when solar energy is not available. Storage may be of a buffer capacity or a long-term capacity. Buffer capacity storage provides for a smooth electric output during periods of intermittent insolation on cloudy days; long-term storage provides for electric output for extended periods beyond the solar day.

The amount of thermal storage beyond any buffer capacity is usually specified in terms of the number of hours of operation that it can provide at the rated turbine generator capacity. Determining the amount of thermal or electrical storage is a complex design problem which depends on the plant configuration, the load characteristics, alternative energy costs, and the desired operating strategy. Operating strategies are discussed later in this section.

Thermal Energy Storage

Thermal energy storage is placed between the collector subsystem and the electrical power generation subsystem. During periods of strong insolation, thermal energy storage accepts excess thermal energy from the collector subsystem and stores it until that time the collector subsystem is unable to satisfy the demands of the EPGS. Thus, thermal energy storage isolates the EPGS from fluctuations in input thermal power, enhancing performance and extending operational flexibility.

Thermal storage may be incorporated into the system in either a "through storage" or a "side storage" arrangement. However, due to the simplicity and operational ease of the "through storage" configuration, it was selected as the preferred arrangement and is the basis of the model. Only moderate temperature (1000°F) sensible-heat storage is considered for SPS Systems.

Performance Projection

Thermal storage systems do not exist commercially, but the loss mechanism has been estimated for a variety of systems[40,8]. The loss model used is described below. It is based on thermal energy losses occurring at a fixed rate which is dependent on system capacity. The loss varies from 6 percent of usable capacity per day for 10 MWh_t capacity units to 3 percent for 100 MWh_t capacity units.

Component Availability

Storage systems are built of commercial available items; tanks, pumps, piping, and insulation. All items are available as well as an established practice for their fabrication.

Cost Projections

For small power systems the Aerospace Corporation[10] has estimated the cost of storage to be given by the relationship

$$C = 20.5\ (kWh_S)^{0.538}/kW_R$$

where

kWh_S = storage capacity (kWh)

kW_R = rated power capacity from storage

Performance Modeling

The performance model used for the thermal storage uses a

fixed daily thermal loss rate based on storage capacity and thermal input and removal based on design and operating conditions. The daily loss is determined by the equation:

$$\text{Loss} = (\text{kWh}_S) \cdot T \cdot f(\text{kWh}_S/C_p)$$

where

kWh_S = storage capacity (kWh)

T = time increment (hours)

f = a universal curve based on Reference (41)

C_p = volumetric thermal capacity of the storage media

Electrical Storage

Electrical storage using batteries is a proven technological approach for decoupling the generation and use of electric energy. It is not specific to solar electric systems but has universal applicability for any form of electric generation. For completeness, data on battery storage efficiency and costs are given; however, they are not included in the solar-thermal computer model. Their incorporation into the solar thermal SPS computer model could be accomplished by a routine which in effect modifies the electrical load and accounts for the battery storage losses. Data on battery storage is based on the EPRI Technology Assessment Guide which lists 1990 as the first year of commercial usage.

Performance of advanced battery storage will be 72 percent.

Cost of storage is estimated to be in the \$50-60/kWh with a most likely cost of \$55/kWh based on a 125 MWh input sized unit i.e., 90 MWe net output.

Storage and Hybrid Dispatch Strategy

Defining an effective storage/hybrid dispatch strategy for a given system configuration depends strongly on the load demand

characteristics relative to the time-varying insolation profiles and can have a significant impact on system performance and economics. Analyzing dispatch strategies involves complex interactions between a large number of variables, including storage capacity, charge/discharge rates, collector field area, solar multiple, turbine/generator part-load efficiency, load shapes, insolation profiles, and backup generation costs. For example, one important design parameter in specifying storage capacity is the solar multiple, defined as the ratio of the system's solar collector/receiver capacity at the design point to that needed to produce rated turbine generator output at the design point. Thus, a solar multiple of 1.5 means that at the design point the system produces 1.5 times the thermal energy needed to run the generator at full load. The excess thermal energy is, of course, sent to storage. The larger the solar multiple, the greater the collector field area relative to turbine size, and hence the greater the amount of energy available for storage. For cost effective designs the collector field and storage are sized to provide a solar multiple consistent with the storage capacity.

Basic storage/hybrid dispatch strategies include sun-following, peak shaving, load shifting, level output, and incremental hybrid dispatch. The simplest storage strategy is sun following, in which the available receiver energy and (if receiver energy is insufficient) thermal or electrical storage energy is first dispatched to meet the load, up to the capacities of turbine generator and available storage energy. Any excess energy from the receiver is then sent to storage for future use, up to available storage capacity. After storage, any additional excess is available for other loads or utility sellback.

A second strategy is peak shaving, in which stored solar energy is used to minimize peak demands on the backup energy or utility source. This strategy may be particularly cost-effective for

utilities, since peak demands are generally met by gas turbine units with high generation costs. Peak shaving is generally implemented by establishing a threshold demand level; above the threshold the solar collector and storage energy is used whenever possible to reduce the load down to its threshold value; below the threshold, energy is sent to storage for future use, and any remaining energy is used to further displace the demand. Utilization of peak shaving dispatch is improved if daily estimates of predicted insolation and demands are available to effectively match the threshold demand level with storage capacity and collector size.

Load shifting is similar to peak shaving as a dispatch strategy except that stored energy is used to displace loads within a specified time period rather than during peak demand times. This strategy may be useful in matching solar thermal electric plants with other dispersed solar plants or in displacing peak loads if the peak demand times are well known.

Level output is a hybrid or combined storage/hybrid operating strategy which maintains turbine generator output at its rated capacity during the specified design operating period. This strategy has the advantages of full reliability and capacity credit for the solar plant, but relies heavily on fossil fuel during poor insolation period and could have control difficulties during periods of rapid insolation fluctuations.

Incremental hybrid dispatch involves the use of hybrid to efficiently supplement solar collector output by bringing the turbine generator up from a part-load, off-design operating point to the maximum efficiency point. This strategy has the potential to make very efficient use of fossil fuel since small supplemental amounts can greatly increase the turbine generator output, thereby utilizing the fuel at a very high incremental heat rate. Generally, this strategy would be implemented by dispatching hybrid whenever the incremental fuel rate is higher than a specified criterion. Control dynamics, as in the level output mode, may be difficult and require shutdown during rapid insolation trainsients.

Balance of Plant

Balance of Plant considerations include those aspects of designing, construction, and operating a SPS other than the subsystems for the collection, conversion, and storage of thermal energy. Items included in balance of plant are:

- Land, site preparation, and yard work
- Piping
- Control System
- Indirect Costs
- Distributable Costs
- Miscellaneous Costs.

For central receiver systems, the land area is dependent on tower location, i.e., cavity or exposed receiver configuration. For the 10 MWe baseline exposed receiver configuration, the collector field land area is 304,000 m^2 and the collector mirror area is 66,704 m^2, giving a ratio of 4.56 for land area to mirror area. For the cavity receiver, the baseline case gives a land-to-mirror area ratio of 4.01. This includes allowing a 10,000 m^2 area for plant equipment to the 49,600 m^2 land area covered by the heliostat field.

The balance of plant equipment has both costs and losses associated with their installation. The losses for piping and electrical distribution and costs allowances are given in Table 2-13.

The balance of plant cost figures is the percent addition to capital costs for major subsystems to compute total plant cost. It includes indirect costs as engineering fees and contingency allowance (8 percent), distributable costs such as construction building equipment common to all subsystems (4 percent), site and yard work (3 percent), control system (2 percent), and miscellaneous costs (1 percent). The parenthetical values are for a central receiver system[16,21].

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TABLE 2-13. BALANCE OF PLANT LOSS

TYPE OF SYSTEM	BALANCE OF PLANT COST	BALANCE OF PLANT LOSS
Central Receiver	18%	1.5%
Dispersed - Trough	22.8%	7%
Dish-Thermal	24%	7%
Dish-Electrical	22.8%	2.2%

2.2.7 Computer Model

The computer model for solar thermal electric power systems permits simulation of the combinations of subsystems and components comprising potential SPS configurations. It is written in modular form using FORTRAN IV and is designed to run either stand-alone or integrated with the overall SAI impacts analysis programs and provides detailed hourly statistics on plant performance subsystem efficiencies, and power distribution. In the following section a short description of the main program, major subroutines, their interaction, and data input requirements for each program element are given.

Simulation Model Description

The simulation model of a solar power plant is developed in a modular manner accomplished by the application of a main program, QAG, which contains a number of subroutines to calculate subsystem performance. The modular approach is monitored by flags included in the main line in order to eliminate configuration with a 10-15 kWe open/closed Brayton gas turbine.

In the initial specification of the system, a Design Point Flag is used to establish system size and performance parameters. For this condition, the design point flag is set to equal 1. The first input parameters specify the sun's elevation, azimuth, direct solar insolation, etc. at the design point. The output establishes the plant design parameters by simulation of a solar power plant for optimum conditions. These parameters are further used to size and cost the plant. Figures 2-47, 2-48, and 2-49 illustrate the operation of the SPS model at a macro level.

A description of each subroutine, their function and their operation is given in the following paragraphs. Data input requirements for each subroutine and the mainline are given in the following.

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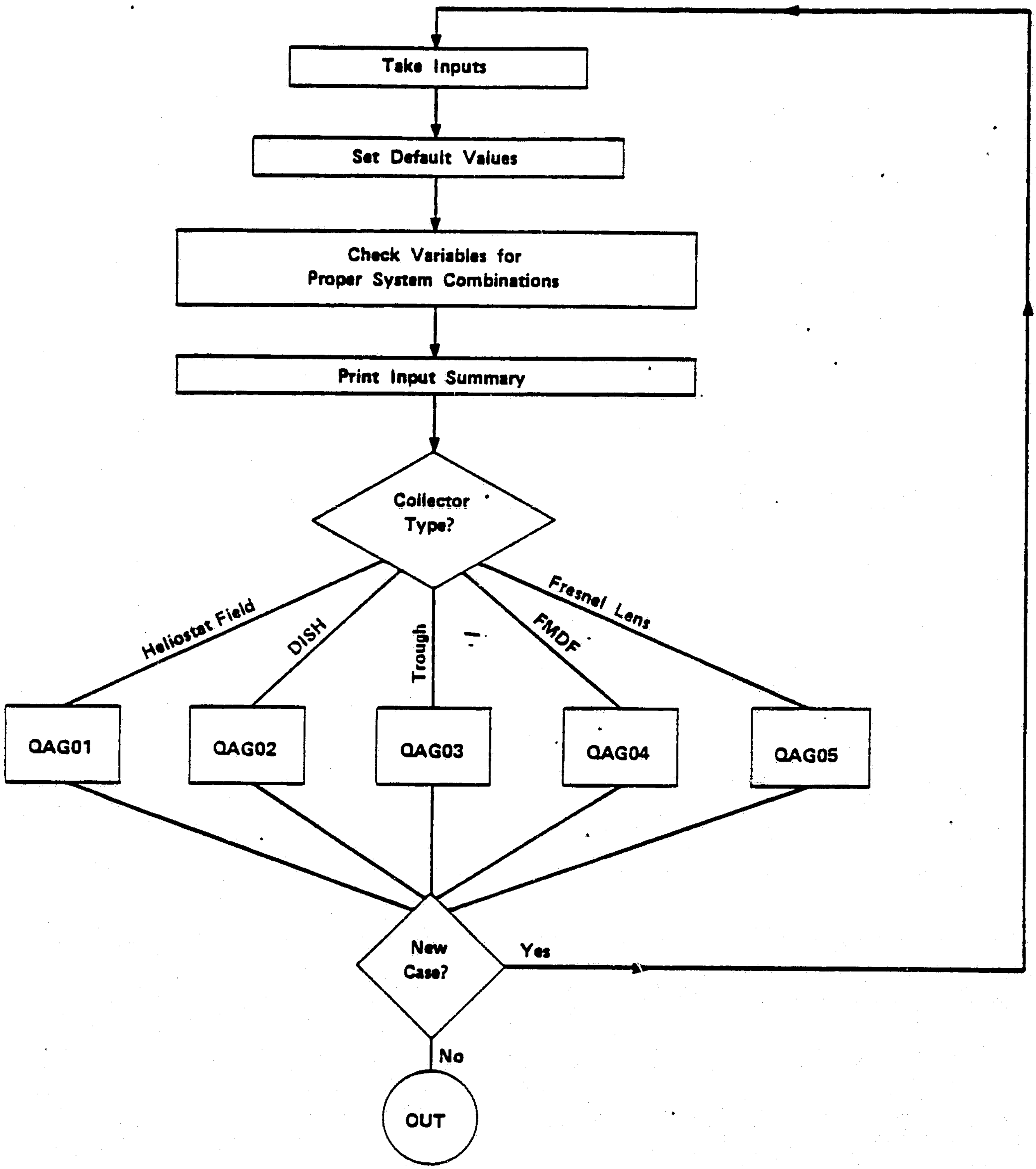

FIGURE 2-47. QAG FLOW CHART

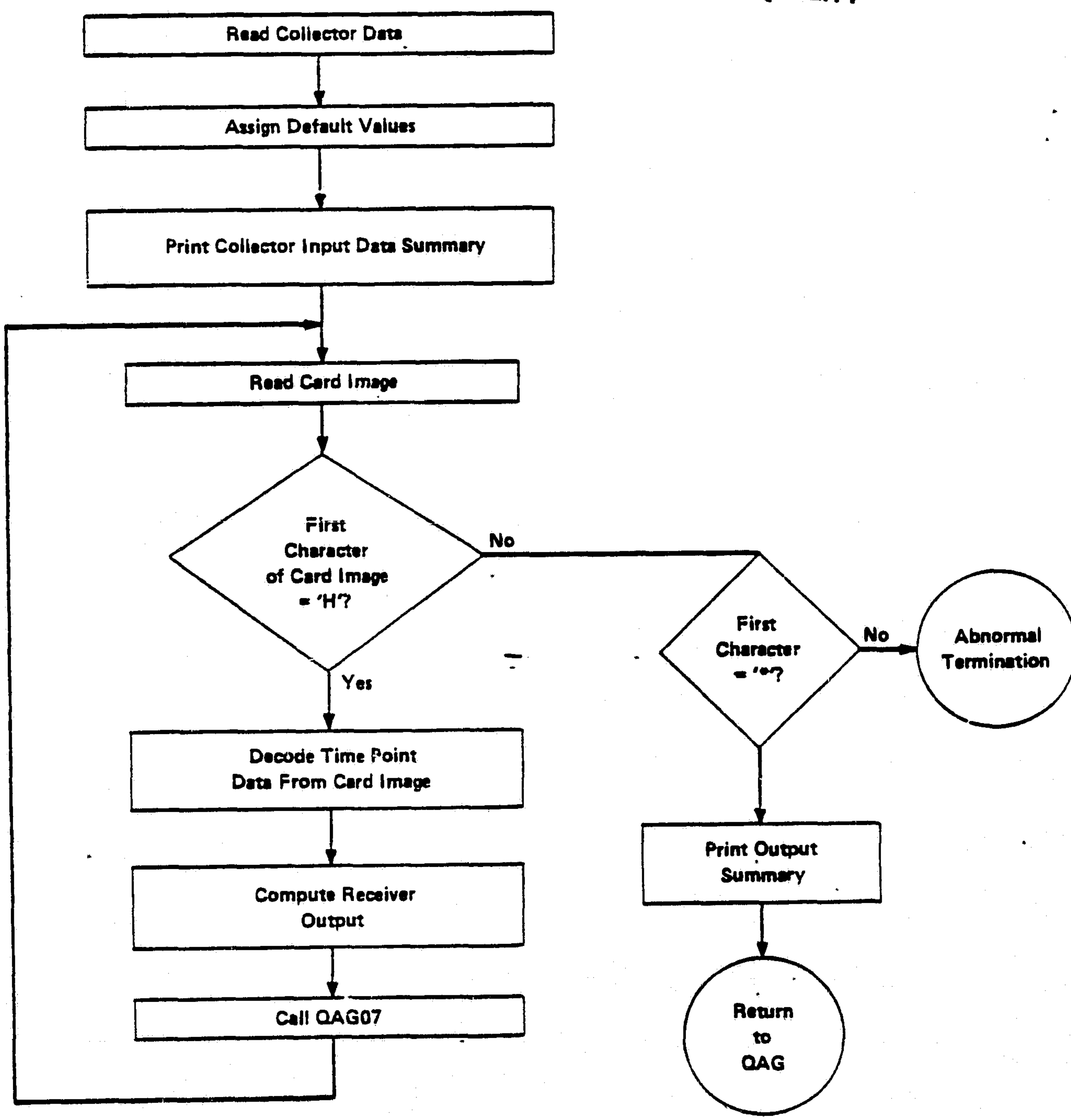

FIGURE 2-48. FLOWCHARTS FOR QAG01-QAG06

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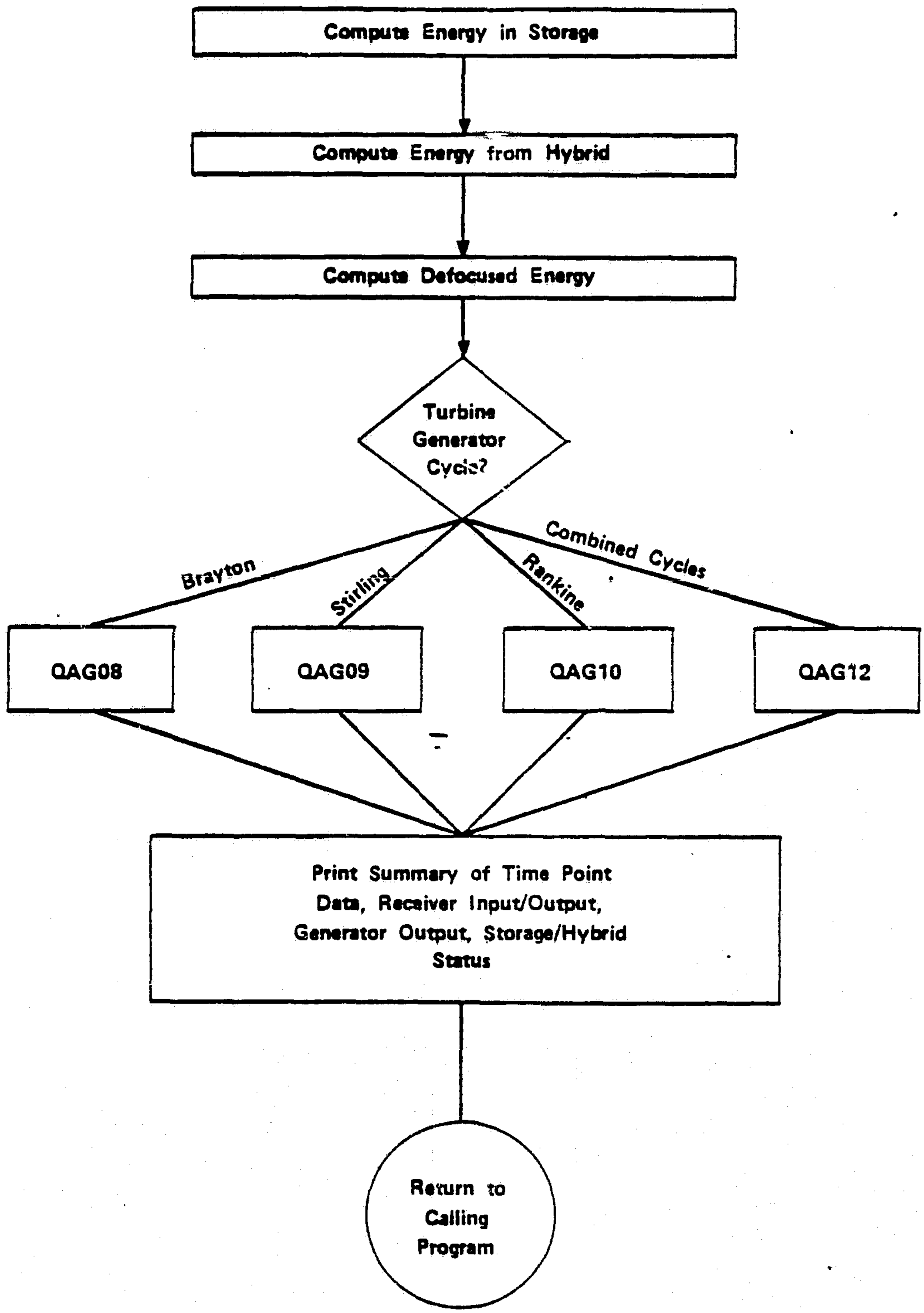

FIGURE 2-49. QAG07 FLOW CHART

1) QAG01. This subroutine computes the power input, RIN, into the receiver for a central receiver configuration. Once RIN, Receiver Input Power, has been computed, control reverts back to the main line, QAG.
2) QAG02. This subroutine computes the power input RIN into a dish collector.
3) QAG03. This subroutine computes the power output, ROUT, for a trough collector configuration.
4) QAG04. This subroutine computes the power output, ROUT, for a Fixed Mirror Distributed Focus Configuration.
5) QAG05. This subroutine computes the power input, RIN, for Fresnel lens.
6) QAG06. This subroutine is a numerical integration subroutine to calculate the collector field efficiency of the Dish Collector. It is called by QAG02.
7) QAG07. This subroutine calculates and maintains status of the storage/hybrid addition to the simulation of a solar power plants. It is called by the collector/receiver subroutines: QAG01, QAG02, QAG03, QAG04, and QAG05. Its data inputs are:
   - TSCAP - Thermal Storage Capacity (kWhr)
   - TSEFF1 - Thermal Storage Input Efficiency
   - TSEFF2 - Thermal Storage Output Efficiency
   - TSINIT - Minimum Energy in Thermal Storage (kWhr)
   - TSVCP - Thermal Storage Volumetric Heat Capacity ($MJ/M^3 - C$)
   - FUEFF - Hybrid Fuel Usage Efficiency

   These data inputs are requested by the mainline QAG and are made available through "Common" statements.

   Data output consist of:
   - Fuel usage (kWhr)
   - Energy available in thermal storage system (kWhr)
   - Design point turbine input (kW)
   - Defocused energy (kWhr)
   - Total energy output (kWhr)

8) QAG08. This subroutine computes the Turbine/Generator output for and open or closed Brayton cycle. It is called by subroutine QAG07. Its data inputs are:

- ADBT - Atmospheric Dry Bulb Temperature (°C)
- AP - Atmospheric Pressure (PSIA)
- NYR - Year of Operation

These data inputs are made available by a "Common" statement.

Data output include:

- TGOUT - Turbine generator output (kWe)

9) QAG09. This subroutine computes the Turbine/Generator output for a Stirling engine. It is called by QAG07. Data inputs and outputs are identical to those of QAG08.

10) QAG10. This subroutine computes the Turbine/Gerator output for a Rankine cycle. It is called by QAG07. Data inputs and outputs are identical to those of QAG08.

11) QAG12. This subroutine computs the Turbine/Generator output for an engine using a combined cycle. It is called by QAG07. Data inputs and outputs are identical to those of QAG08.

12) QAG13. This subroutine is common to the central receiver, parabolic dish, and Fresuel lens configurations. It computes the receiver power output, ROUT. Data inputs for this subroutine are made available through a "Common" statement. It is called by: QAG01, QAG02, and QAG05.

- Data Requirements

Input and output data are summarized below for each subroutine parameter units and default values and indicated in parentheses.

QAG (MAIN PROGRAM)

QAG Inputs:

NCST - Collector Subsystem Type

=1, Heliostat Field/Cavity Receiver

=2, Heliostat Field/Exposed Receiver

NCST - Collector Subsystem Type (continued)

=3, Parabolic Dish

=4, Trough

=5, Fixed Mirror Distributed Focus (FMDF)

=6, Fresuel Lens

NTCT - Thermodynamic Cycle Type

=1, Open Brayton

=2, Closed Brayton

=3, Stirling

=4, Rankine

=5, Combined Cycles

NSHCT - Storage/Hybrid Configuration Type

=1, No Storage/No Hybrid

=2, No Storage/Hybrid

=3, Storage/No Hybrid

=4, Storage/Hybrid

NPWER - Turbine/Generator Power Rating

=1, 10-15 kWe

=2, 1-10 MWe

=2, 4-22 kWe

LOST - Heat Transfer Fluid Index

=1, Steam

=2, Gas

=3, Liquid Metal

SYSLOS - Piping Loss Index, depends on LOST index and NCST as shown below:

	LOST INDEX		
NCST	1	2	3
1	0.98	0.90	0.97
2	0.98	0.90	0.97
3	0.93	0.93	0.93
4	0.90	0.83	0.89
5	0.90	0.83	0.89
6	0.93	0.93	0.93

NYR - Year of Operation
*CWS - Maximum Allowable Wind Spped (16 m/s)
TITMX - Maximum Allowable Turbine Inlet Temperature
AP - Atmospheric Pressure
RDELT - Receiver/Turbine Inlet Temperature Difference
SMULT - Solar Multiple
*NMOD - Number of Collector/Receiver Modules (1)
NCDT - Central or Dispersed. Plant configuration type.
=1, Centralizer
=2, Dispersed
*ELOSS - Electrical Loss Factor For Dispersed System Type (0.97)
TSCAP - Thermal Storage Capacity (kWhr)
TSEFF1 - Thermal Storage Input Efficiency
TSEFF2 - Thermal Storage Output Efficiency
TSINIT - Minimum Energy in Thermal Storage (kWhr)
TSVCP - Thermal Storage Volumetric Heat Capacity (MJ/M^3 - CO

QAG Outputs:

- Prints out a summary of the inputs.
- Assigns input values or default values to all variables mentioned in the input section.

Time Point Meteorological Data Inputs

At each time point, subroutines QAG01, QAG02, QAG03, QAG04, and QAG05 are provided with time point data. These data are read from hourly solmet weather tapes by a subroutine written by SAI. The following input data list is required by the collector subroutines:

TIME	-	Time of day (hours since midnight)
AZ	-	Solar Azimuth (degrees)
EL	-	Solar Elevation (degrees)
IDN	-	Direct Normal Insolation (kW/m^2)
ABDT	-	Ambient Dry Bulb Temperature (^oC)
WS	-	Wind Speed (m/sec)

QAG01 (CENTRAL RECEIVERS)

QAG01 Inputs:

*CA	-	Collector Area (m^2) (14,869 for cavity and 66704 for exposed)
*CREF	-	Mirror Reflectivity (0.88)
*RCVL	-	Receiver Convection Loss Factor (0.03 for cavity/0.05 for exposed)
*RREFL	-	Receiver Reflection Loss Factor (0.05 for both)
*RCNL	-	Receiver Conduction Loss Factor (0.03 for cavity/0.0 for exposed)
*REM	-	Receiver Effective Emissivity (1.0 for cavity/0.9 for exposed)

Meteorological Time Point Data

QAG01 Outputs:

Computes ROUT, the receiver output power (kW).
Prints a summary of Fuel Usage, current energy in storage, design time point turbine input power, energy lost by defocusing collectors, total electrical energy generated.

QAG02 (DISH COLLECTOR)

QAG02 Inputs:

*DD - Dish Mirror Diameter (M) (11 m)
*DRD - Dish Receiver Outer Diameter (M) (0.4 m)
*DREF - Mirror Reflectivity (0.88)
*RCVL - Receiver Convection Loss Factor (0.05)
*RREFL - Receiver Reflection Loss Factor (0.05)
*RCNL - Receiver Conduction Loss Factor (0.03)
*DSE - Mirror Reflected Beam Slope Error (milliradian) (3.5)
*DPE - Reflected Beam Pointing Error (milliradian) (3.5)
Meteorological Time Point Data

QAG02 Outputs:

- Computes ROUT, Receiver Output Power
- Prints Output Summary

QAG03 (TROUGH COLLECTOR)

QAG03 Inputs:

*TL - Trough Length (m) (2.1 m)
*TW - Trough Width (m) (1.2 m)
*TTILT - Trough Tilt Angle for North-South Trough Axis (degrees)(0.0)
*TREF - Mirror reflectivity (0.81)
*TABS - Absorptivity of receiver tube surface (0.95)
*TPE - Trough pointing effort (degrees) (0.01)
*TFLAG - Trough Direction Indicator (1.0)
=1, North-South trough axis
=2, East-West trough axis
Meteorological Time Point Data

C-6

OAGO3 Outputs

- Computes ROUT, receiver output power (KW)
- Prints output summary

OAGO4 (FIXED MIRROR, DISTRIBUTED FOCUS)

OAGO4 Inputs:

*FAPD - Fixed Mirror Diameter (m) (60.98)
*FTILT - Tilt Angle of Fixed Mirror (degrees) (15.0)
*FREF - Mirror Reflectivity (0.88)
*FABS - Receiver Surface Absorptivity (0.9)
Meteorological Time Point Data

OAGO4 Outputs:

- Computes ROUT - receiver output power (KW)
- Prints output summary

OAGO5 (FRESNEL LENS)

OAGO5 Inputs:

*FLD - Lens Diameter (m) (1.73)
*FAD - Receiver Aperture Diameter (m) (0.5)
*FRIM - Collector Rim Angle (Radius) (0.873)
*ETRATUS- Lens Transmissivity (0.9)
*RREFL - Receiver Reflection Loss Factor (0.05)
*RCVL - Receiver Convection Loss Factor (0.05)
*RCNL - Receiver Conduction Loss Factor (0.03)
*FSIGL - Standard Deviation of the Mirror Surface Normal Irregularities (Radius) (0.0035)
Meteorological Time Point Data

QAG05 Outputs:

- Computes ROUT, Receiver Output Power (kw)
- Prints Output Summary

Storage and Hybrid Dispatch Algorithm

Various storage and hybrid dispatch strategies for solar thermal electric systems are currently being implemented by SAI as part of Task 4 methodology development.

These dispatch strategies include sun following, peak shaving, load shifting, level output, and hybrid incremental dispatch, as described previously. In the dispatch algorithm described below, sun following is implemented by setting DMD equal to the load demand; peak shaving is implemented by reducing DMD to the load demand minus the threshold demand level, then resetting DMD before Step 3; level output is implemented by setting DMD at the maximum turbine generator capacity during the design operating period (zero otherwise) and HIFR greater than the maximum hybrid heat rate; load shifting is implemented by using the peak shaving algorithm with the threshold set at the full demand during the required time period and zero elsewhere; and the incremental hybrid dispatch strategy is implemented by setting HIHR as the desired incremental heat rate. The dispatch aglorithm is described below:

1. Directly dispatch available receiver energy and (if receiver energy insufficient) storage energy (thermal or electric) up to capacities of turbine generator, storage, or power conditioning to meet output load demand DMD.

2. Send any excess energy to storage, up to storage capacity.

3. Send any excess energy after storage to additional output power, up to rated capacity of generator and/or power conditioning (this may drive output power to exceed the load, i.e., excess will be available for sell-back; this available excess is monitored as a separate energy credit).

4. Wasted energy due to limited storage or generator capacities is monitored over the simulation period.

5. If remaining load demand is still positive, and if hybrid is available, hybrid is dispatched unless the incremental heat rate exceeds a specified value HIFR (but, not to exceed the capacity limits of turbine generator, hybrid dispatch, power conditioning, and load demand).

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APPENDIX D

SOUTHERN CALIFORNIA EDISON UTILITY RESULTS

APPENDIX D
SOUTHERN CALIFORNIA EDISON UTILITY RESULTS

Southern California Edison (SCE) is a large investor-owned utility serving about 30% of the total electrical load of California. The service area of SCE is shown in Figure D-1.

D.1 BASELINE SCE UTILITY SYSTEM (1980)

The utility information in this section was obtained primarily from two sources: The Electricity Forecasting and Planning Report (Docket No. 77-EA-8) submitted by SCE to the California Energy Resources Conservation and Development Commission on September 16, 1977, and the SCE 1978 hourly load profile.

In October 1980, SCE announced a revision of its load forecast and generating plant expansion plant for the period 1980-1990 and beyond. The revised plan was significant in that SCE now plans to construct far more renewable energy source plants such as solar thermal electric and geothermal than were advocated in the 1977 plan. Wherever possible in this report, data from the 1980 revised plan has been identified and compared to the corresponding data from the 1977 plan.

D.1.1 Load Characteristics

The peak load for SCE for 1980 was predicted to be 13,288 MW. An annual load growth rate of 5% is projected for the 1980-1990 period, resulting in a projected peak load of 19,233 MW in 1990. The SCE load peaks in early fall, as shown by the monthly peak demand profile (Figure D-2). From June to September, the monthly peak is greater than 90% of the annual peak. The month with the lowest peak load is January.

Hourly demand profiles for two days are shown in Figure D-3. The days are September 25, the day with the highest peak demand for any day in the year, and January 1, the day with the lowest peak demand for any day in the year. For both days, the peak demand occurs in the afternoon: at 1500 hr for

FIGURE D-1. Service Area of SCE

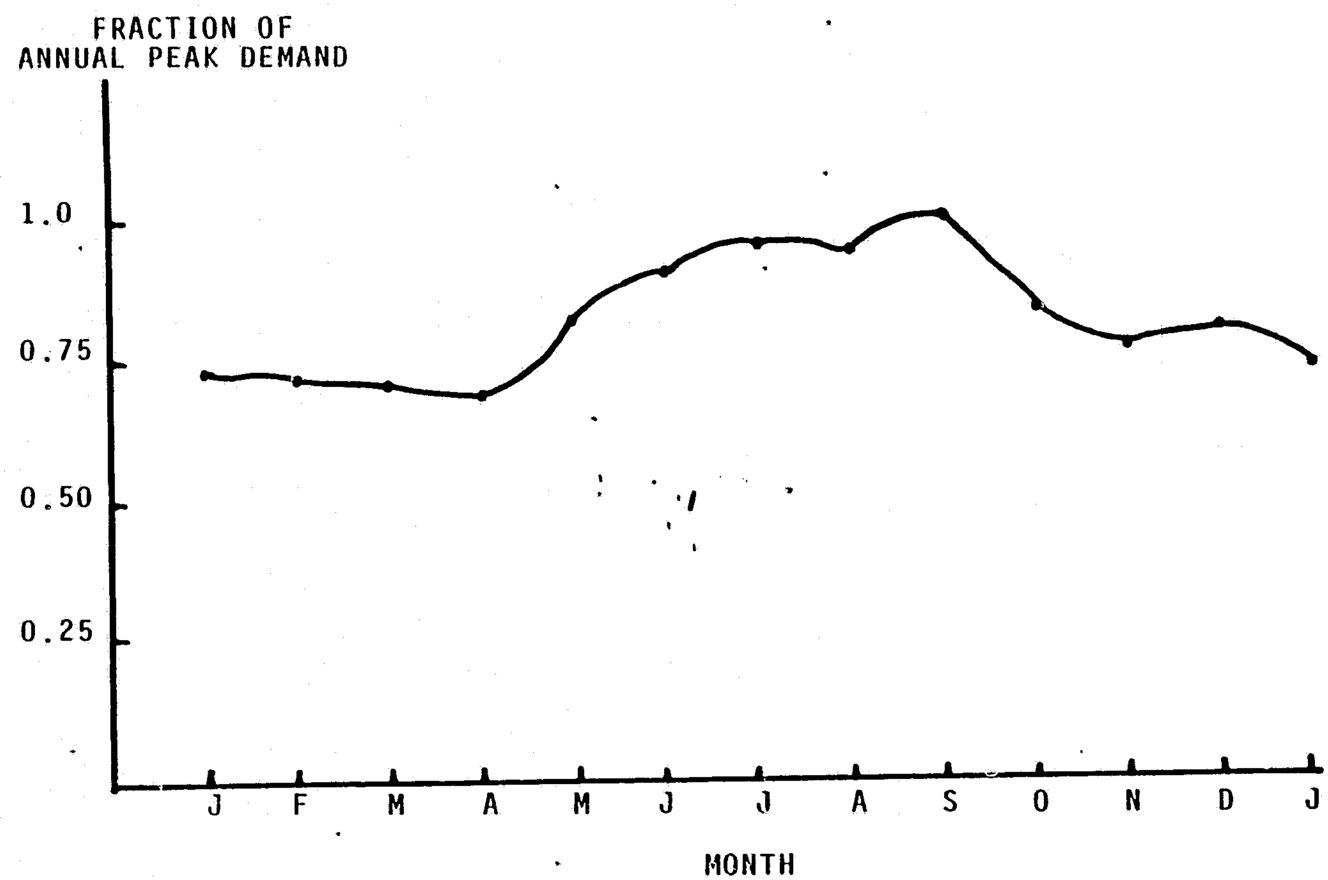

FIGURE D-2. Load Characteristics for the SCE Utility
Monthly Peak Demand Profile: 1978

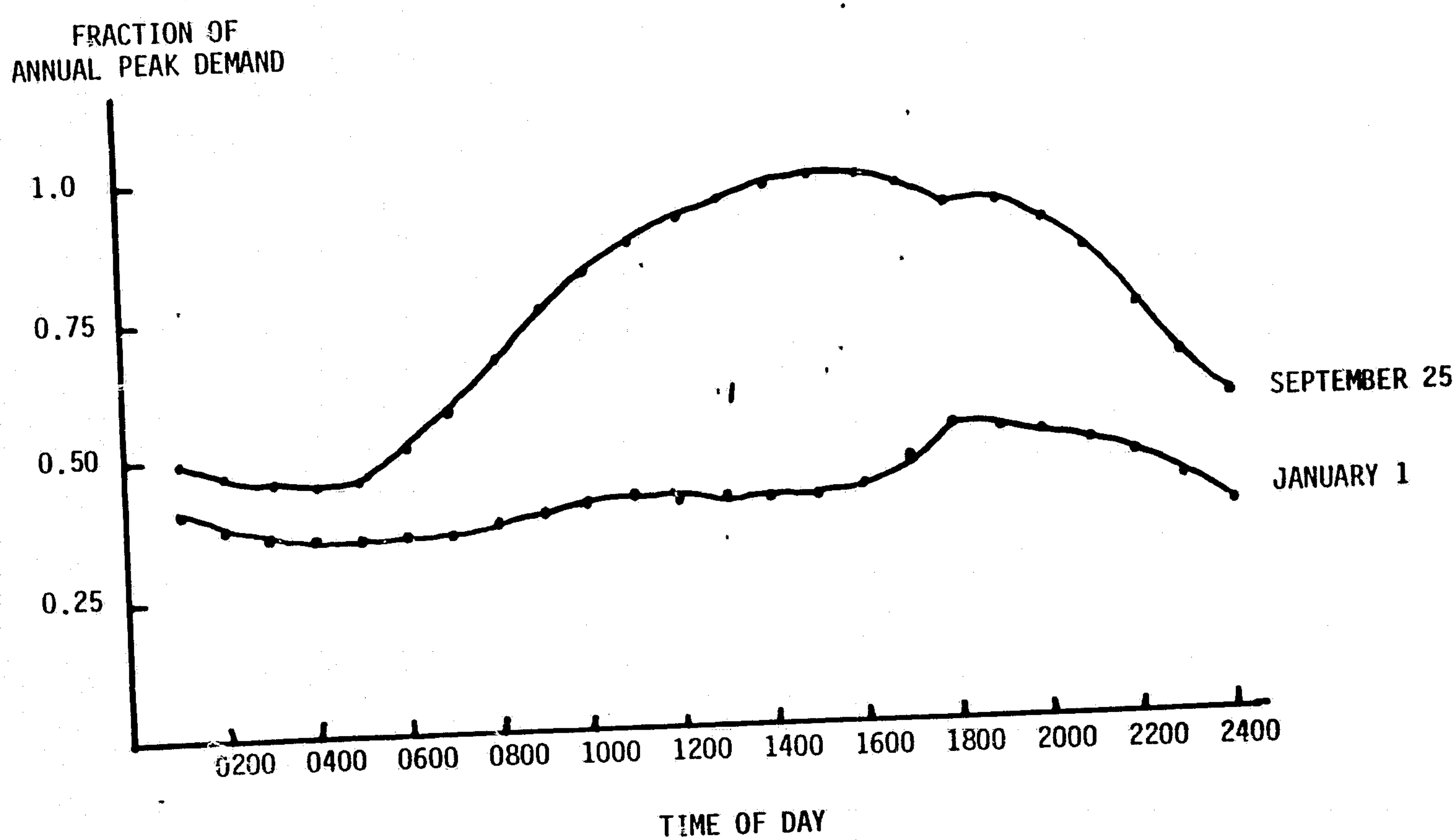

FIGURE D-3. Load Characteristics for the SCE Utility Hourly Demand Profile: 1978

September 25 and at 1800 hr for January 1. From 1200 hr to 1800 hr on September 25, the load is greater than 90% of the peak for the day.

Based on the load characteristics, three major conclusions may be drawn regarding solar system configuration and performance.

First, solar system economic performance will be reduced because the peak demand and peak radiation level periods of the year do not coincide. The peak demands for SCE occur in August and September, while the peak radiation months in the southern California area typically June and July. Therefore, the potential for reducing peak demand and the installed capacity required to meet the peak demand is diminished.

Second, use of storage and hybrid configurations will result in substantially less savings for the SCE utility than the other utilities previously analyzed. This is due to the nature of the load shape and poor demand curve solar output curve match. In September solar output peak occurs around noon and tapers off to zero at about 1900 hr. However, the solar peak occurs around 1500 hr, with the demand above 95% of the peak from 1500 hr to 1700 hr. Thus, a substantially sized (and less-cost effective) storage system is required for any capacity displacement, because the demand peak occurs about 3 hours after the solar peak, and remains at or near that level for 4 hours, and because the solar output is not in its peak season. Hybrid systems will also be less effective for SCE than for the other utilities. Since the hourly load is fairly flat over a long number of hours during the day when solar is not available, most of the units operating at that time will be intermediate and base rather than peaking. Therefore, the hybrid fuel will displace less expensive intermediate and base fuel, resulting in reduced savings when using the hybrid system. Finally, a turbine cycle combining high efficiency at low input power and low capital cost is required. The Rankine and closed Brayton systems have good low input power efficiencies, but are fairly expensive. The open Brayton has poorer low input power characteristics, but is substantially less expensive. For that reason, the open Brayton was chosen for the SCE system.

D.1.2 Financial Parameters

The required financial parameters for SCE are shown in Table D-1. The major differences between the SCE and investor-owned utility (IOU) financial parameters are the net income tax rate (52.7% for SCE vs. 50% for IOU) discount rate (12% for SCE vs 10% for IOU) and the investment tax credit (10% for IOU vs. 4% for SCE). As a result of these differences, the total cost for either a conventional generating plant or a solar plant is greater for SCE than for IOU. This will result in the total levelized annual revenues (reduction in conventional generation system costs) resulting from use of solar plants also being greater for SCE than for IOU. However, due to the increased cost fo the solar plants, the solar breakeven prices and solar system net worth will be lower for SCE than IOU.

D.1.3 Generating System Reliability

Southern California Edison's conventional generation system is significantly different than the IOU system. The differences between the two systems are in some cases off-setting, so that it is not possible to determine their net effect on the solar system economics.

First, the reliability requirments for SCE are stringent. The required LOLP is approximatey .000006, or about one outage every twenty years. This compares to the IOU LOLP of .001. In addition, an installed capacity reserve margin of 18± 2% of the annual peak load and a daily spinning resreve of greater than 7% of the peak demand for the day are required.

Second, the SCE plants are more reliable than the IOU plants as shown by Table D-3a in Section D.1.4 which lists the heat rate and forced outage rates for the SCE plants. A comparison with the IOU plant forced outage rates (Table 4-2a) shows that the SCE nuclear and distillate oil plants are three to four times more reliable than the IOU plants. This difference is due in part, to the difference in size between the SCE and IOU plants. For example, the IOU utility has access to an 800 MW nuclear plant, while the SCE has access only to an 80 MW nuclear plant prior to 1980. The larger IOU plant naturally has a higher forced outage rate than the smaller SCE nuclear plant.

TABLE D-1. SCE Financial Parameters

PARAMETER		VALUE
WEIGHTED COST OF CAPITAL (DISCOUNT RATE)		12%
EFFECTIVE INCOME TAX RATE		52.7%
PROPERTY TAX		2.6%
INSURANCE		.1%
INVESTMENT TAX CREDIT		4%
DEPRECIATION		DDB WITH SWITCHOVER TO SL
PLANT LIFE	- STEAM	35Y
	- HYDRO	35Y
	- ALL OTHERS	35Y
ACCOUNTING LIFETIME		30Y

Other features contributing are age (the SCE plant is 9 years old, whereas the IOU plants are averages of all existing plant characteristics) and capital costs.

D.1.4 1980 Baseline System Generating Plant Characteristics

Even though both SCE and IOU are large investor owned utilities operating in the Southwest U.S., their plant mixes are substantially different. The baseline SCE existing generation capacity breakdown is shown in Table D-2. Almost 60% of the SCE utility capacity is residual oil generation, with about 10% coal generation. There is no gas generation. On the other hand, almost 50% of the IOU utility capacity is gas generation, with about 25% coal generation. Only about 6% of the IOU utility capacity is residual oil generation.

The characteristics of the individual plants are given in the following pages. Table D-3a lists the reliability and efficiency characteristics, Table D-3b the plant costs, and Table D-3c the annual maintenance schedule for the plants. Because of the large number of individual plants in the SCE system, Tables D-3a and D-3b are divided up by generating unit type only, rather than by type and size as for the municipal, IOU, and isolated utilities.

D.1.5 Expansion System Capacity Characteristics (1990)

An expansion of the SCE system to 1990 must take into account the increased costs and increased time required for planning and construction of nuclear plants. To take this into account, two different expansion scenarios were explored: one with the full nuclear expansion specified in the 1977 SCE Planning Report, and another with the expansion restricted so that the last two nuclear plants listed in the 1980-1990 period in the report were not allowed to be installed. These expansions in turn were compared to the SCE expansion. Table D-4 lists the expansion restrictions on each generating unit type for both expansion scenarios. Due to the difficulty in modeling the time-dependent nature of the wind output, wind systems were not allowed in the expansion.

TABLE D-2. Baseline SCE Existing Generation Capacity Breakdown (1980)

PLANT FUEL TYPE	CAPACITY (MW)	% OF UTILITY CAPACITY
RESIDUAL OIL	8,914	57.9
DISTILLATE OIL	550	3.6
COMBINED CYCLE	1,011	6.6
NUCLEAR	349	2.3
HYDROELECTRIC	774	5.0
COAL	1,631	10.6
SUBTOTAL	13,229	86.0
PURCHASED POWER & POWER EXCHANGES	2,174	14.0
TOTAL	15,403	100.0

TABLE D-3a. 1980 Baseline and 1990 Expansion SCE System Generating Plant Characteristics

GENERATING UNIT TYPE	HEAT RATE (BTU/KWHR)	FORCED OUTAGE RATE (%)
RESIDUAL OIL	8,935-13,319	1.20-5.61
DISTILLATE OIL	12,100-14,470	3.11-3.21
COMBINED CYCLE	9,119	4.7-5.9
NUCLEAR	10,266	3.95
HYDROELECTRIC	--	1.0
COAL	9,600-10,570	11.19

TABLE D-7b. 1980 Baseline and 1990 Expansion SCE System Generating Plant Costs

GENERATING UNIT TYPE	CAPITAL COST ($/KW)	FUEL COST ($/MBTU)	O&M COST[2] ($/KW/Y)
RESIDUAL OIL	--	3.5	2.7
DISTILLATE OIL	323	4.7	8.1
COMBINED CYCLE	620	4.7	8.1
NUCLEAR	1,078-1,270	0.7	5.4
HYDROELECTRIC	665	---	91.7
COAL	1,320	1.4	49.9
GEOTHERMAL	1,402	---	12.1
WIND	1,846	---	10.8
FUEL CELL	916	4.7	

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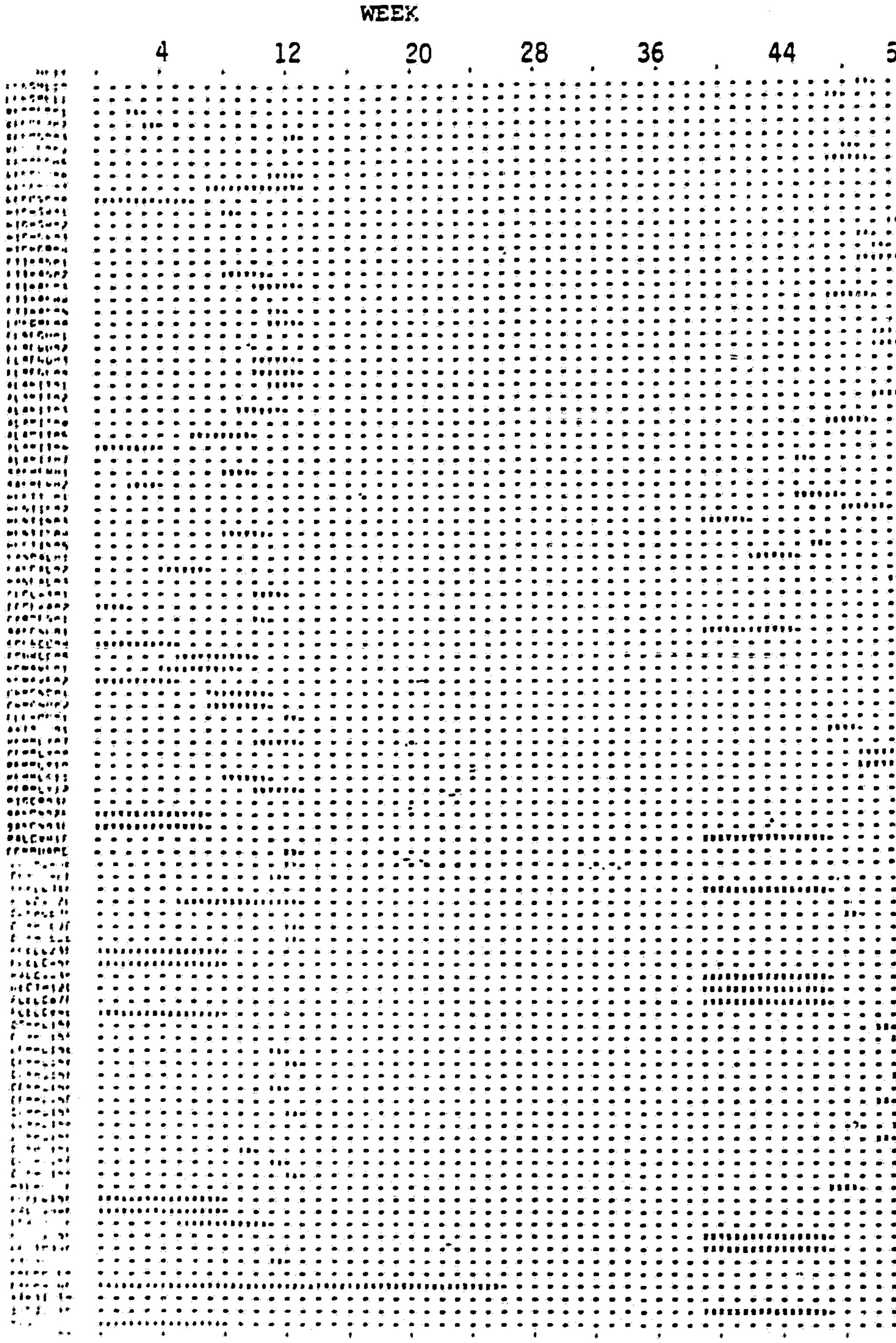

TABLE D-3c. SCE Annual Maintenance Schedule for 1990 Expansion

X = UNIT ON MAINTENANCE
- = UNIT AVAILABLE

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TABLE D-4. SCE Expansion Restrictions for SAI Analysis

PLANT FUEL TYPE	RESTRICTIONS
RESIDUAL OIL	NO EXPANSION ALLOWED
DISTILLATE OIL	NO RESTRICTIONS
COMBINED CYCLE	NO RESTRICTIONS
NUCLEAR	SCENARIO #1: UPPER LIMIT OF 3744 MW SCENARIO #2: UPPER LIMIT OF 3084 MW
HYDROELECTRIC	FIXED EXPANSION (171 MW)
COAL	NO RESTRICTIONS
GEOTHERMAL	UPPER LIMIT OF 200 MW
WIND	NO EXPANSION ALLOWED
FUEL CELL	SCENARIO #1: FIXED EXPANSION (390 MW) SCENARIO #2: NO RESTRICTIONS
GAS	NO EXPANSION ALLOWED (SCE HAS NO EXISTING GAS UNITS)

A comparison of the SCE and SAI plant expansions to 1990 is shown in Table D-5. The Scenario #1 and Scenario #2 plant capacities as well as the SCE 1977 and 1980 plan capacity projections are listed.

The SCE expansion total system capacity for both scenarios are within 1% of the 1977 SCE plan capacity. This is well within the error caused by lack of precision in input data such as outage and heat rates. The SCE expansions have about 8% more capacity than the 1980 SCE Plan, due to the fact that the load projections for 1990 were reduced in the 1980 plan below the values in the 1977 plan.

D.2 SCE UTILITY SYSTEM WITH SOLAR POWER GENERATION (1990)

Two different types of solar systems were evaluated for the SCE systems:

- Open Brayton, No Storage, No Hybrid (Phoenix and Ft. Worth Sensitivities)
- Open Brayton, 3 Hr Electrical Storage, No Hybrid

Both the Scenario #1 and Scenario #2 expansions were evaluated for the no storage, no hybrid case. Only the Scenario #1 expansion was used for the electrical storage case.

Also, the Scenario #2 no storage, no hybrid case was evaluated over a range of solar penetrations of about 2.5 to 10% of the peak load. The other cases were evaluated only a solar penetration of at 5.43% of the peak load.

D.2.1 Solar System Savings

The solar system savings vs solar penetration level for the open brayton cycle for the SCE utility shown in Figure D-4. Also shown in the Figure are the solar system savings for the IOU utility. As discussed in the Financial Parameters section, the SCE savings are higher than the IOU savings for the same turbine cycle due to the higher discount rate and overall tax rate, and lower investment tax credit.

TABLE D-5. Plant Capacity by Generating Unit Type
Expanded SCE Utility System (1990)

GENERATING UNIT TYPE	PLANT CAPACITY (MW)			
	SCENARIO 1. SAI PROJECTION	SCENARIO 2. SAI PROJECTION	1977 PLAN SCE PROJECTION	1980 PLAN SCE PROJECTION
RESIDUAL OIL	8,914	8,914	8,914	
DISTILLATE OIL	3,689	4,166	1,192	9,084
COMBINED CYCLE	1,011	1,011	2,731	
COAL	2,070	2,741	2,631	3,534
NUCLEAR	3,744	3,084	3,715	2,678
HYDROELECTRIC	914	914	914	2,153
GEOTHERMAL	200	200	200	750
WIND	0	0	70	120
FUEL CELL	390	0	390	130
SOLAR (STE, PV, PONDS)	0	0	0	310
COGENERATION	0	0	0	300
SUBTOTAL	20,932	21,025	20,782	19,059
FIRM TRANSFERS	1,169	1,169	1,169	1,169
TOTAL	22,101	22,194	21,951	20,228

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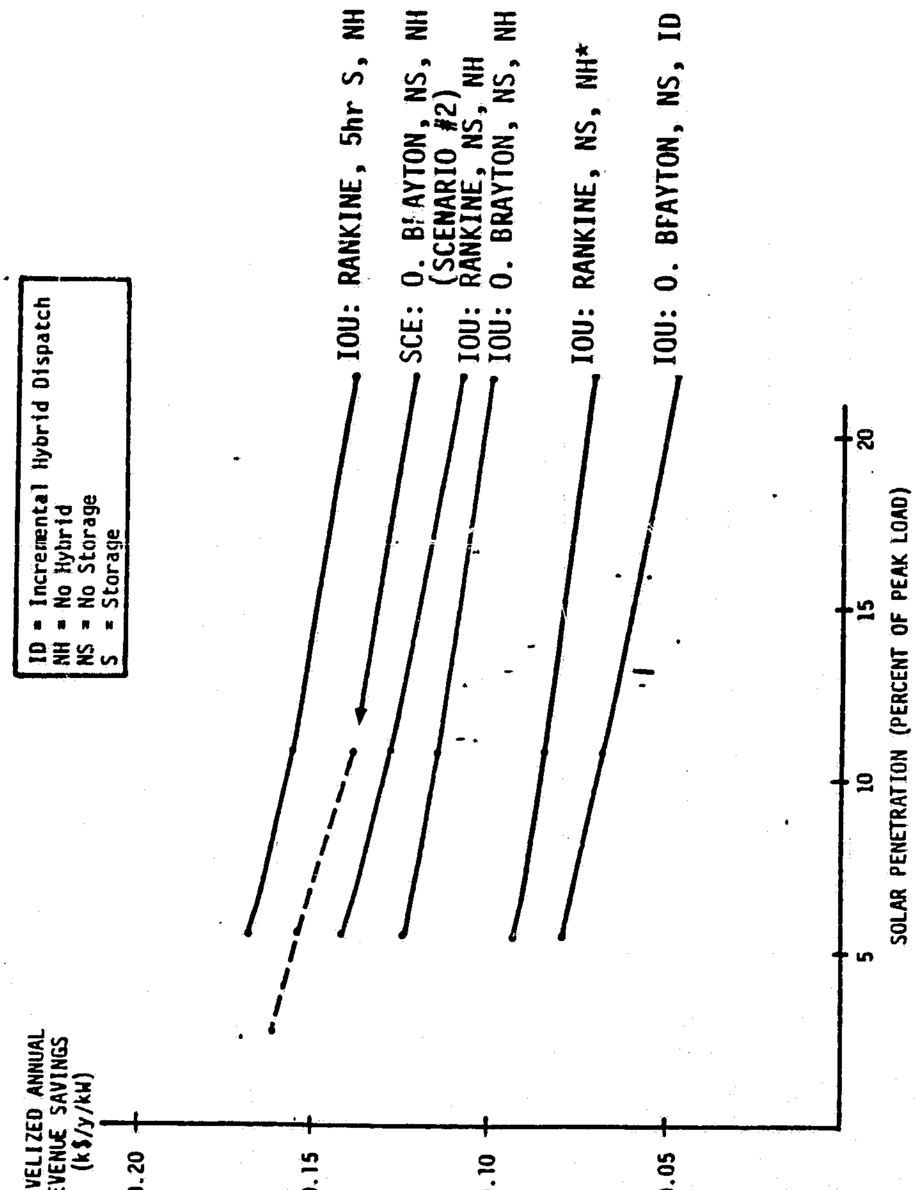

*Fort Worth Site Sensitivity.

FIGURE D-4. Solar System Savings - SCE and IOU Total Cost Savings Comparison

The breakdown in solar system savings by capital, O&M and fuel illustrates both similarities and major differences between the SCE and IOU utilities.

Figure D-5 is the solar system savings for SCE for the open brayton cycle broken down by total fuel savings, total capital savings, and total O&M. At low penetration levels (2.5% peak load) the capital savings make up more than 2/3 of the solar savings with O&M about 1/3 and fuel savigns negligible.

During most of the year, the demand is significantly less than the installed capacity (due to reserve margin) even accounting for maintenance and outage rates. Therefore, at the low penetration levèl, the solar will displace mostly the unneeded capacity and a small amount of fuel. As the penetration increases, and the installed capacities approach the demand level, fewer MW of capacity may be displaced per MW of solar and so fuel displacement increases dramatically. At 10% penetration the fuel savings are 2/3 of the total savings.

One interesting observation is the total cost savings breakdown corresponding more to the IOU Rankine 5hr storage breakdown (Figure 4-7) than to either the IOU Open Brayton (Figure 4-10) on the IOU Rankine (Figure 4-4). This is caused by the load characteristics and economics. The SCE open Brayton system displaces capacity because it is available to be displaced and the high costs (taxes, discount rate) push capital displacement over füel displacement. The IOU Rankine 5 hr storage displaces capacity because, due to the storage, power is available from the solar system during periods of peak demand. The IOU open Brayton, no Storage, no Hybrid case displaces mostly fuel because the solar output and demand peak occur closer together, and because it is less beneficial financially to displace capacity in the IOU case than in the SCE case.

The savings from fuels displaced also changes by penetration level. Figures D-6 and D-7 show the solar system savings by fuel type and capacity type for the SCE system. At low penetration levels, coal fuel is displaced, but more residual and distillate oil one used. This is due to the SCE load

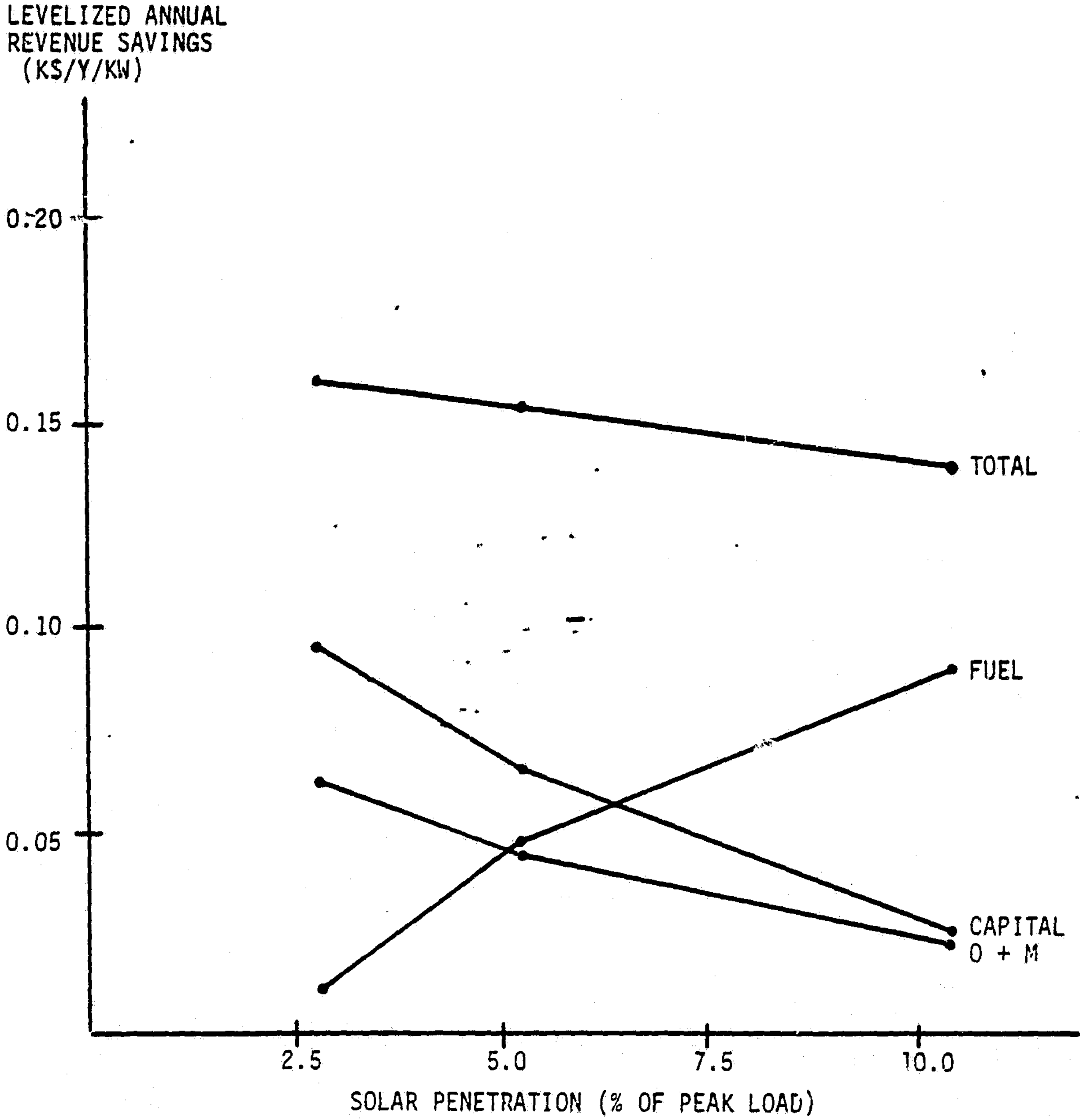

FIGURE D-5. Solar System Savings - SCE Open Brayton,
No Storage, No Hybrid Total Cost Savings Breakdown

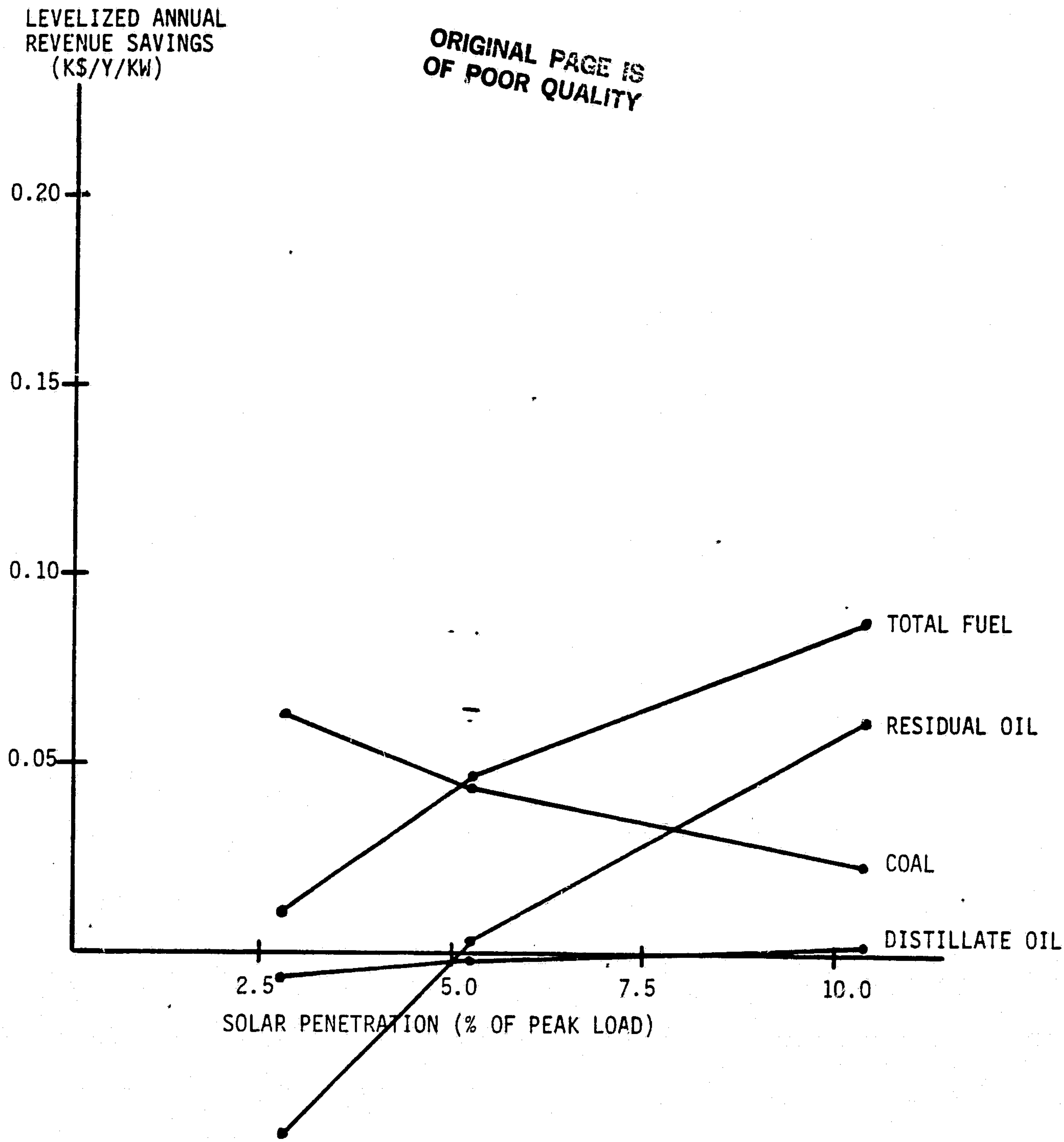

FIGURE D-6. Solar System Savings - SCE Open Brayton, No Storage, No Hybrid Fuel Cost Savings Breakdown

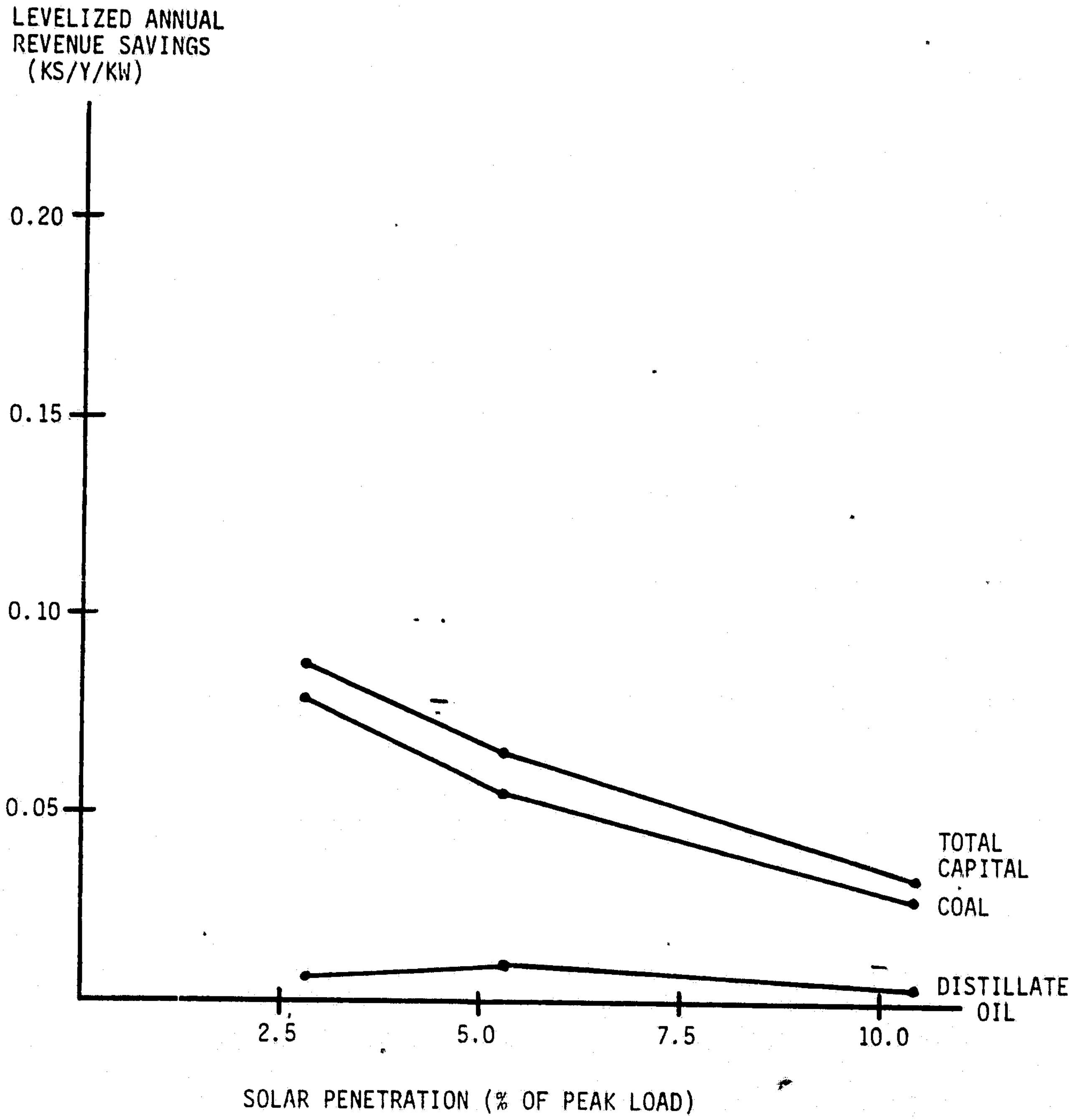

FIGURE D-7. Solar System Savings - SCE Open Brayton, No Storage, No Hybrid Capital Cost Savings Breakdown

charactristics. The peak demand occurs hours after the peak solar output, so that base (load), rather than peaking (oil), capacity is displaced. Coal fuel is also displaced. However, the peak load is still about the same, now with less coal capacity and fuel use. Therefore, more distillate and residual oil peaking capacity is used to make up for the loss in coal. As the solar penetration level increases for the SCE case, the solar output cuts more deeply into the peak demand. As this occurs, less base capacity (coal) is displaced (per MW of solar output) and more fuel is displaced. At 10% penetration, the fuel savings are due mostly to the reduction in use of residual and distillate oil, and the capital cost savings have been substantially reduced.

A comparison of the Scenario #2 expansion results in the highest savings. Figure D-8 shows the total cost savings breakdown for four open Brayton systems at 5.43% penetration: no storage, no hybrid, Scenario #2; no storage, no hybrid Scenario #1, and Ft. Worth, no storage, no hybrid, Scenario #1. As shown, the highest savings occur for the scenario #2 (restricted nuclear) case, although the two scenarios result in similar savings. The electrical storage savings is substantially less, as explained in D.1.1. Finally, the Ft. Worth sensitivity shows as expected, considerably less savings. This insolation level is not indicative of southern California, but is used to illustrate how a similar utility in Texas or Northern California may be effected.

The breakdown of the cost savings by fuel, O&M and capital shows that the capital and O&M savings are fairly constant for the four cases. The difference in cost savings is due almost entirely to the differences in the fuel savings. This should be viewed from the perspective of the capital cost as a percentage of the total cost. For the SCE Ft. Worth case, the subjective system output is far less than for the SCE Phoenix case: it is comparable to the SCE Phonix system at a lower penetration of the savings at low penetration levels. In the same way, the output of the systems are less than the comparable output of the #2 scenario at 5% penetration. The fuel cost savings breakdown is shown in Figure D-9. As expected at the 5% level, reduction in the use of coal results in the major savings, with increased use of distillate residual oil to make up for the decreased coal usage.

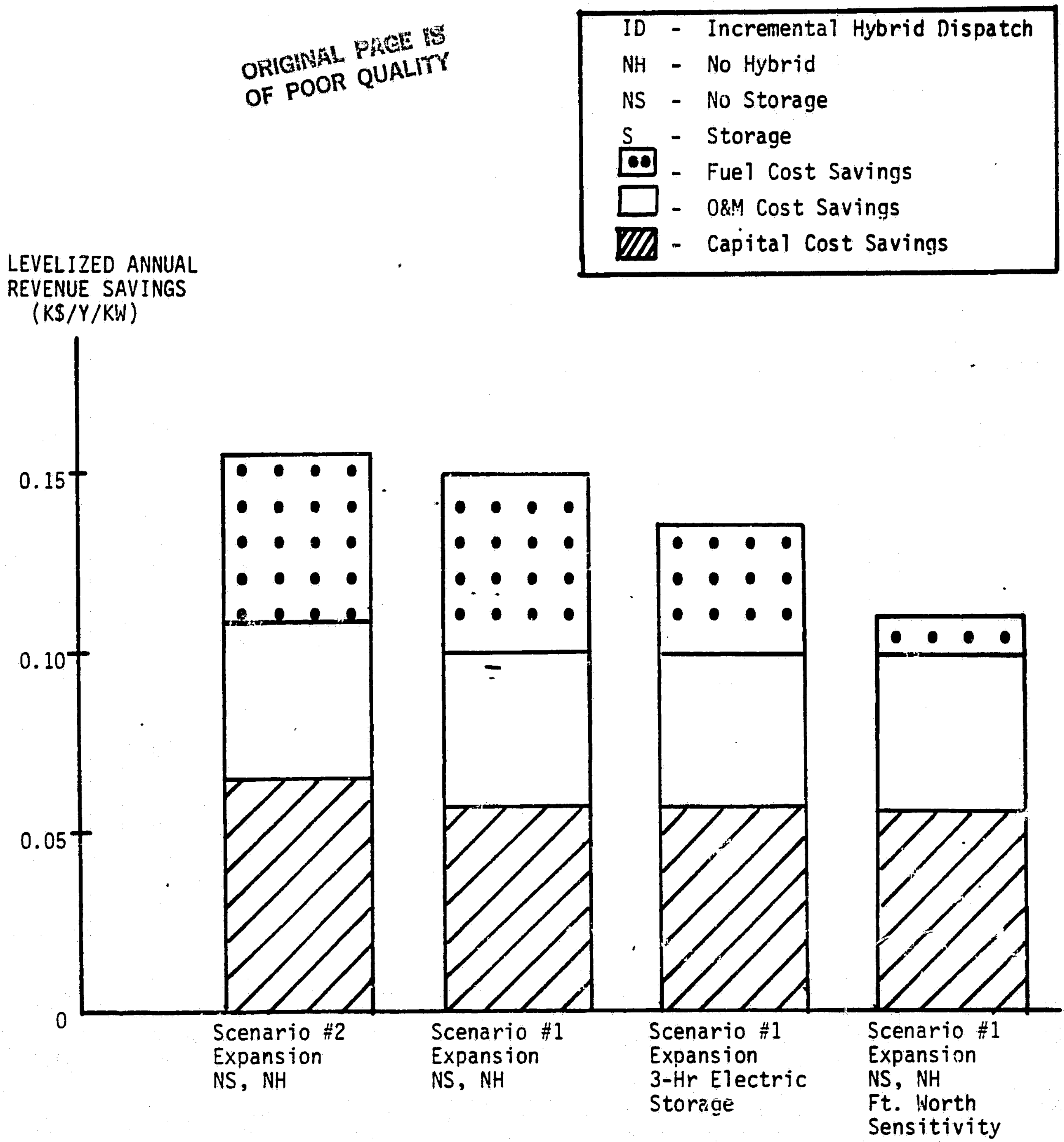

FIGURE D-8. Solar System Savings - SCE Open Brayton
5.43% Solar Penetration
Total Cost Savings Breakdown

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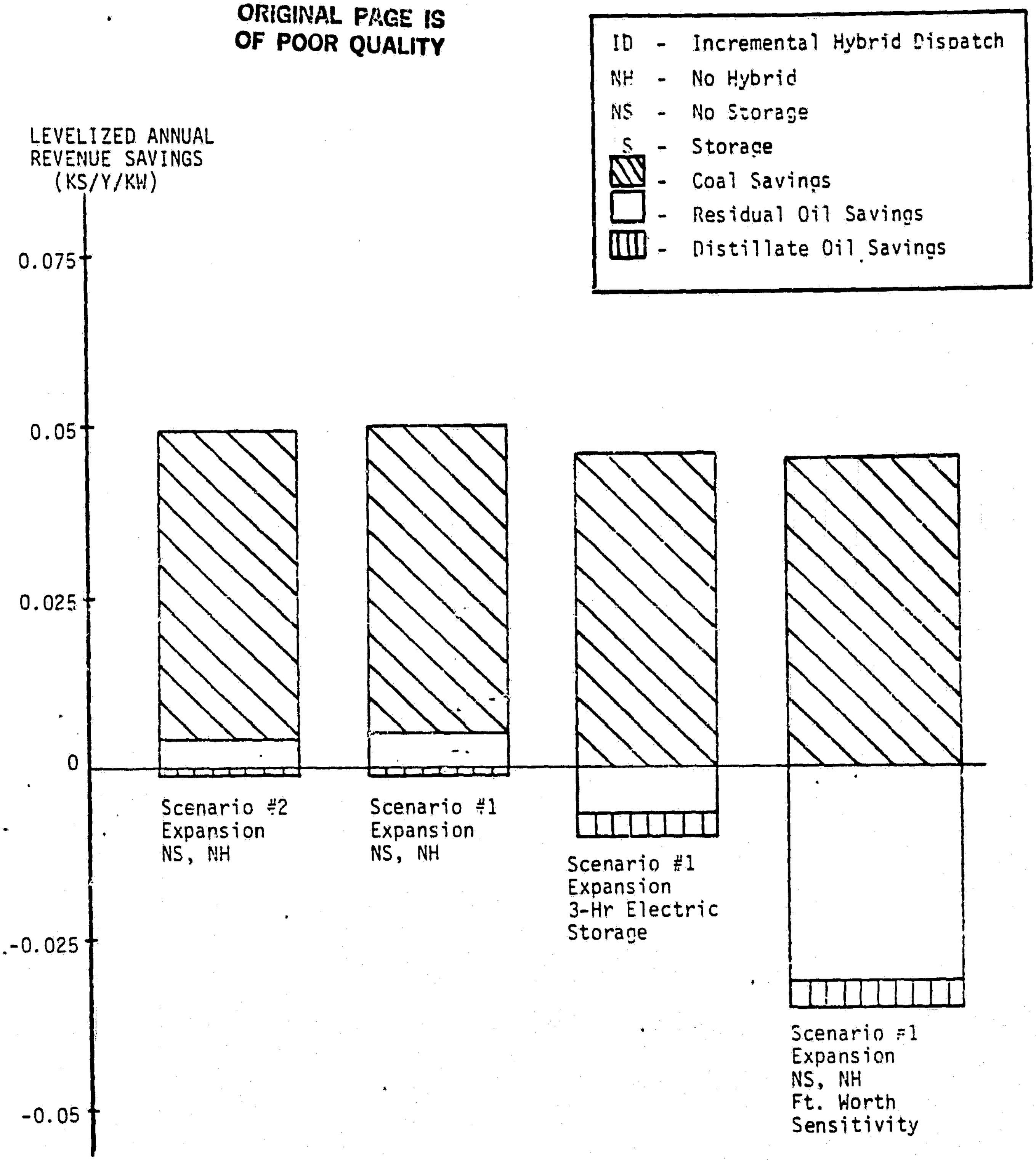

FIGURE D-9. Solar System Savings - SCE Open Brayton
5.43% Solar Penetration
Fuel Cost Savings Breakdown

D.2.2 Solar System Breakeven Prices

The solar system breakeven prices for the SCE utility vs penetration level for open Brayton cycle, Scenario #2, is shown in Figure D.10. The breakeven costs for SCE are lower than those of the IOU utility, even though the solar system savings were higher, as was discussed in the Financial parameters section. Again, though, the SCE curve is adjacent and almost parallel to the IOU curve, indicating that the IOU is a good model of utilities like SCE. The breakeven prices range from $1.34 at 2.54% penetration to $1.21 at 10% penetration. These prices are fairly low compared to the other utilities previously analyzed. This indicates that the penetration level for large utilities with economics like SCE will be small (5%) for the next ten years unless a major change in financial parameters occurs or environmental restrictions become a driving factor.

The comparison of the breakeven prices for the four comparison cases shows that not very much can be done to increase breakeven prices, at least with the Open Brayton cycle

Figure D-11 shows the comparison. The breakeven price varies from $1.27 to $0.89/W, depending on the case. The Scenario #2 breakeven prices at very low penetration levels (2%) may reach a value greater than $1.50.

A breakeven price sensitivity performed by varying the O&M, tax credit, property tax, and insurance rates is shown in Table D-6. The table shows that the breakeven price is moderately affected by changes in the O&M tax credit ($0.10/W) but is more substantially affected by changes in the property tax and insurance ($0.20/W). Therefore, favorable property tax laws for solar ownership could have a major impact on solar system price and use.

D.2.3 Solar System Net Worth

The net worth of the SCE solar system is adversely effected by factors previously identified: poor economics, utility size (as a factor in reducing savings resulting from capacity displacement) and a poor demand curve-solar output curve match. As a result, the solar system net worth is

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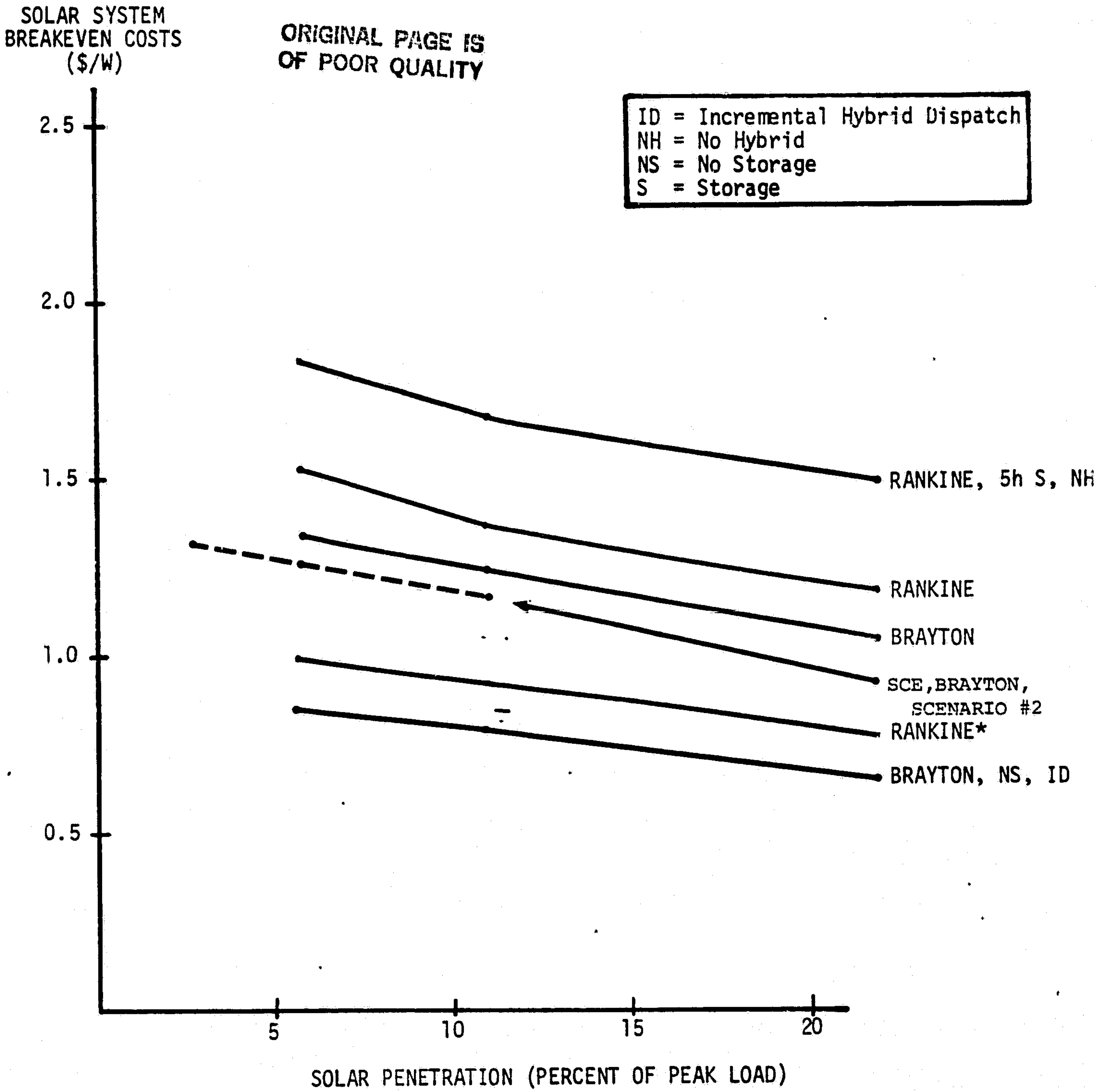

*Fort Worth Site Sensitivity.

FIGURE D-10. Solar System Breakeven Prices - SCE and IOU

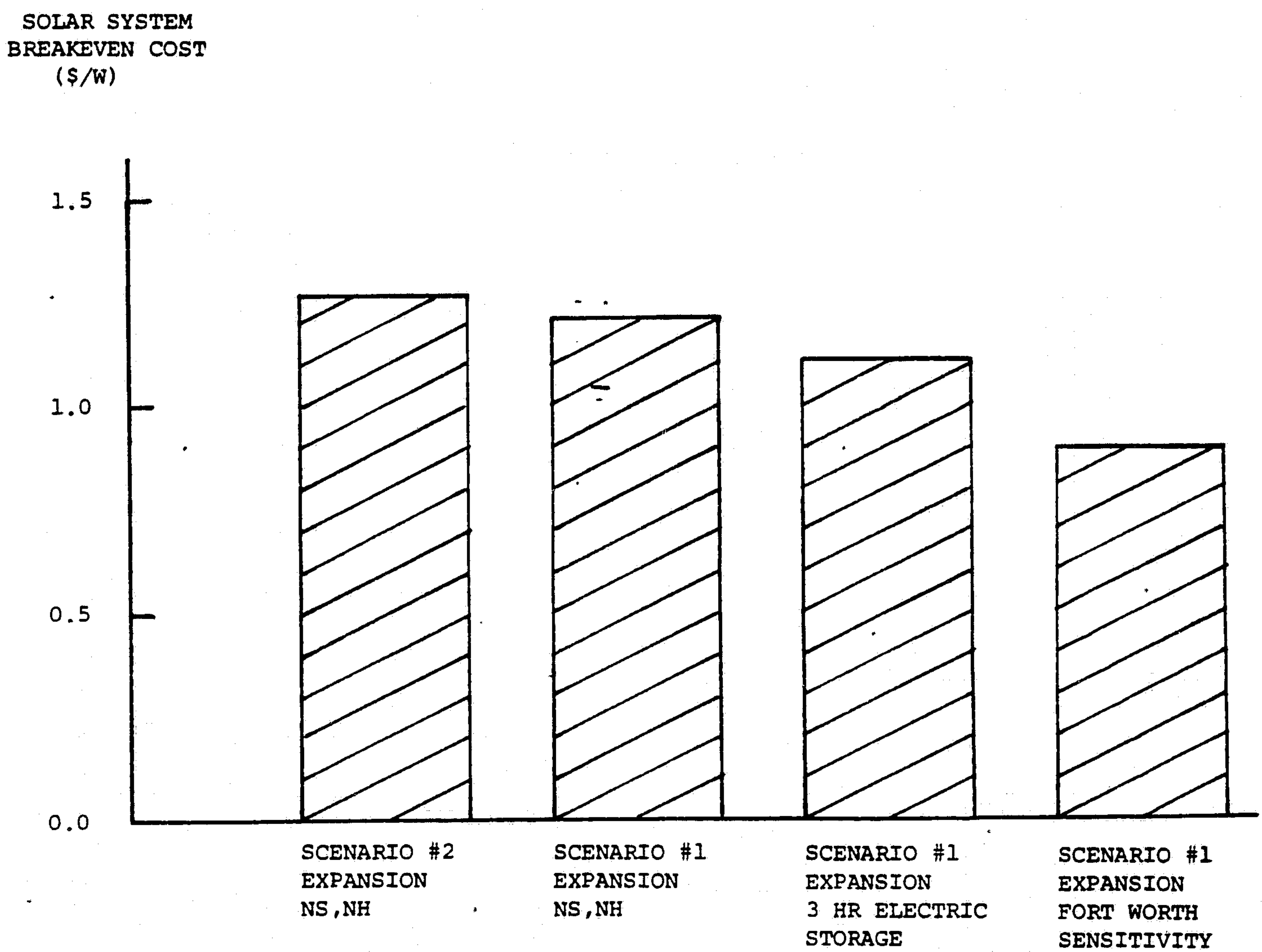

FIGURE D-11. Solar System Breakeven Costs
SCE Utility
Open Brayton
5.4% Solar Penetration
(NS = No Storage, NH = No Hybrid)

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TABLE D-6. Solar System Breakeven Costs-SCE Open Brayton, No Storage, No Hybrid (Scenario #2)
5.43% Solar Penetration
Economic Sensitivity Analysis

Tax Rate : 0.527

Cost of Capital: 0.12

O&M	TAX CREDIT (fraction)	ANNUAL PROPERTY TAX AND INSURANCE (fraction)	SOLAR SYSTEM BREAKEVEN COSTS ($/W)
0.0131	0.04	0.027	0.94
		0.002	1.20
	0.10	0.027	1.00
		0.002	1.18
0.0065	0.04	0.027	0.99
		0.002	1.18
	0.10	0.027	1.05
		0.002	1.27*

*Baseline

less for the SCE utility than the IOU utility, an effect which gets more dramatic as the solar system costs get higher.

The solar system net worth for various solar costs for the SCE utility under the Scenario #2 expansion is shown in Figure D-12. At \$1.00/w solar system cost, the solar penetration level resulting in the maximum net worth is about 8%, with net levelized annual revenues of about 40,000 k\$. At \$1.20/W it is at about 5% with annual revenues of about \$7500, and at \$1.50/W, less than 2.5%. This contrasts with the IOU Open Brayton solar system net worth (Figure 4-18). At \$1.20/W, the solar penetration level resulting in the maximum net worth is about 18% for the IOU with net levelized annual revenues of about 90,000 k\$. At \$2.00/W, it is around 5%, with annual revenues of about \$5000.

The conclusions which may be drawn from the net worth curve is that solar thermal electric systems will be marginally profitable for the SCE utility in the 1980-1990 time frame, provided that the solar costs are kept very low (\$1.20/W). Cost effective solar penetration levels are low (2.5%). Because of the financial characteristics and the poor demand/solar match of the SCE system, use of high solar penetration levels is not likely to be cost effective in the 1980-1990 time frame.

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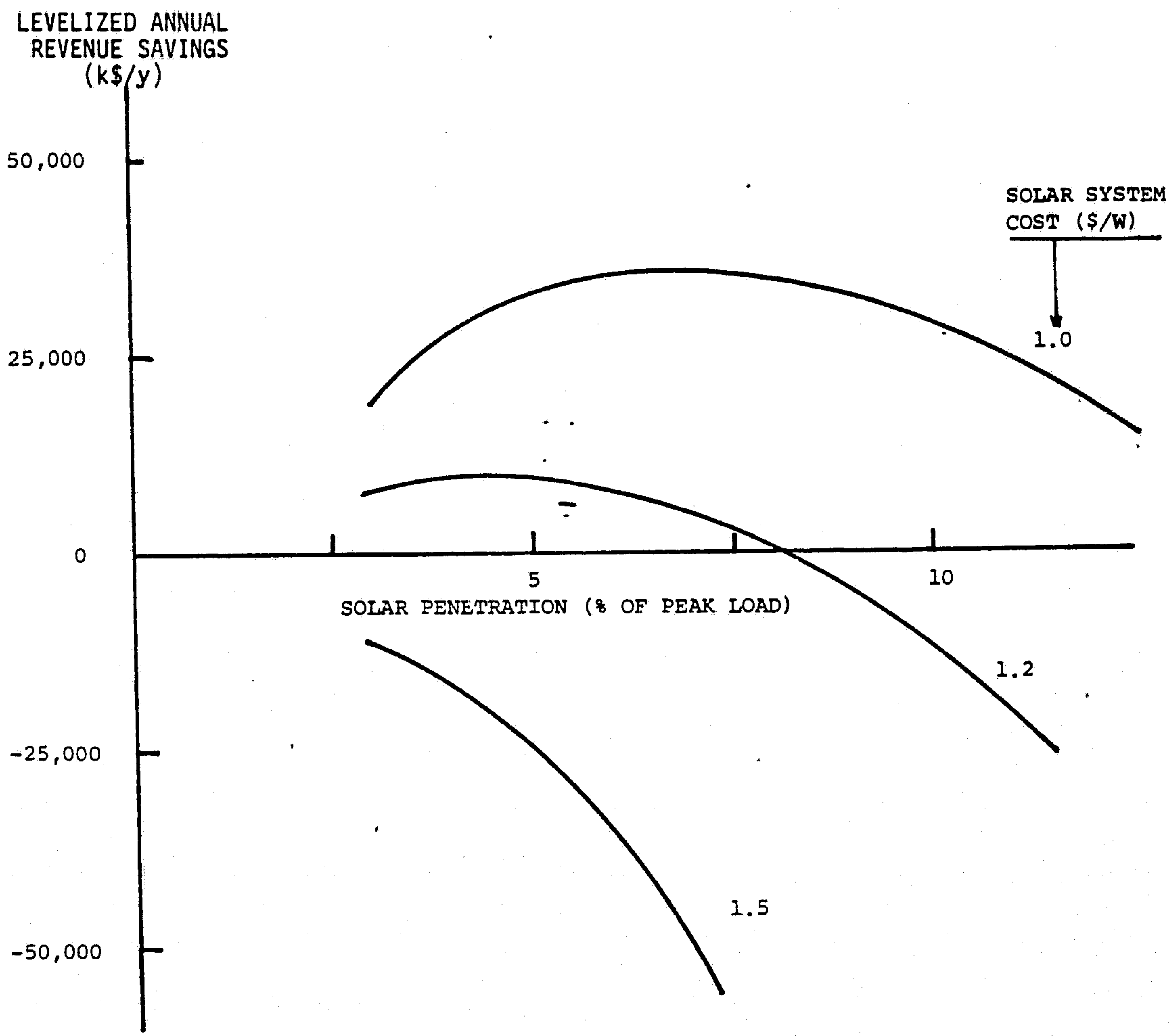

FIGURE D-12. Solar System Net Worth
SCE Utility
Open Brayton, No Storage, No Hybrid System
Scenario #2

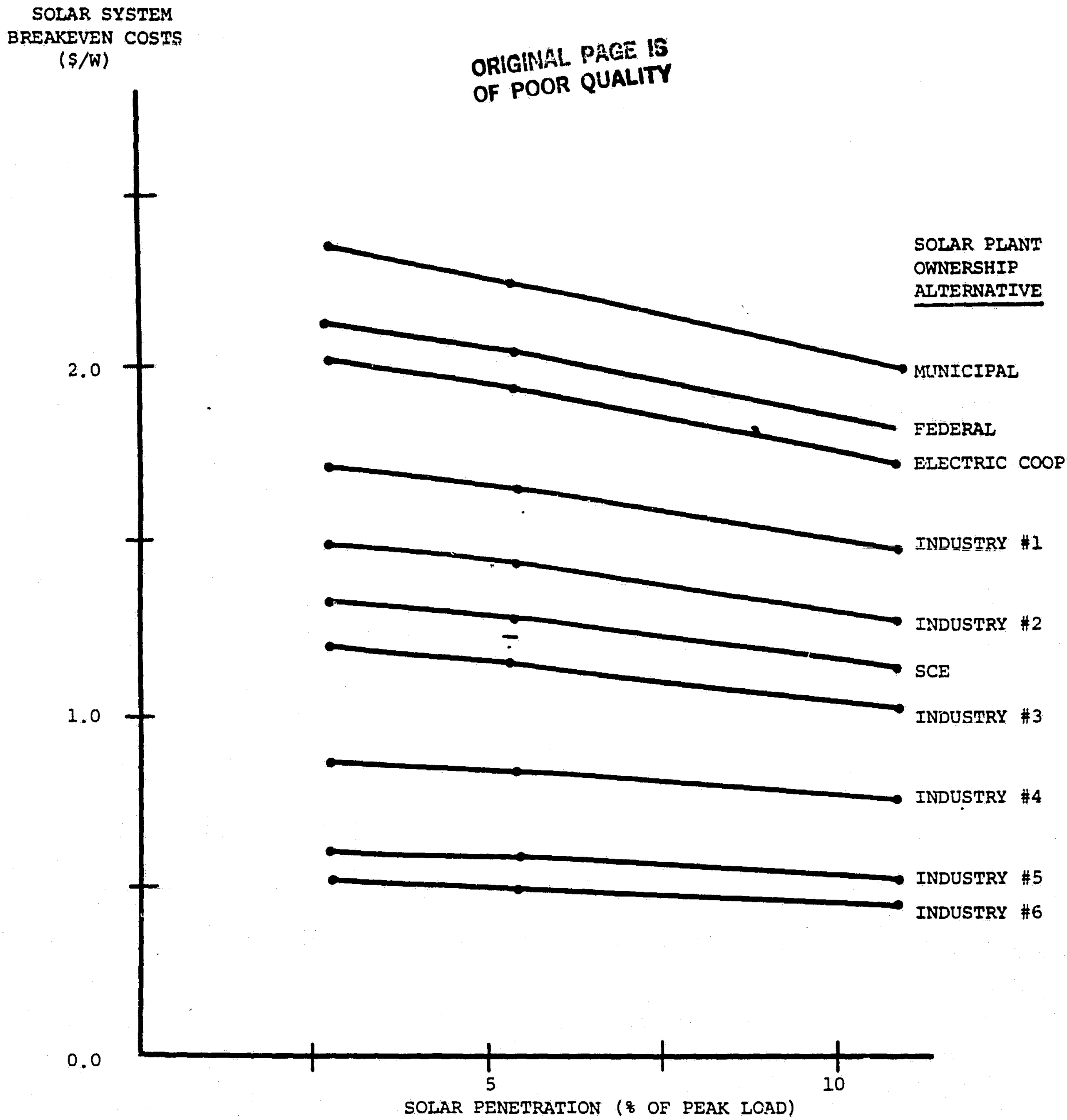

FIGURE D-13. Solar System Breakeven Costs for Various Solar Plant Ownership Options, SCE Utility, Scenario #2